CENTRAL ELECTRICITY REGULATORY COMMISSION

STAFF PAPER ON TRANSMISSION PLANNING, CONNECTIVITY, LONG /MEDIUM TERM OPEN ACCESS AND OTHER RELATED ISSUES

SEPTEMBER,2014

To seek Stakeholder's Views on important issues of Transmission Planning ,Connectivity and Access to Inter State Transmission System in India

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ABBERIVATION

APTRANSCO	Transmission Corporation of Andhra Pradesh limited
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CTU	Central Transmission Utility
GNA	General Network Access
HCPTC	High Capacity Transmission Corridor
IEX	Indian Energy Exchange
ISGS	Inter State Generating Station
ISTS	Inter State Transmission System
LTA	Long Term Access
MTOA	Medium Term Open Access
NLC	Neyveli Lignite Corporation Limited
NLDC	National load Despatch Centre
NHPC	National Hydro Power Corporation
NPCIL	Nuclear Power Corporation of India ltd.
NTPC	National Thermal Power Corporation
POSOCO	Power System Operation Corporation
PGCIL	Power Grid Corporation of India Limited
PTC	Power Trading Corporation
PXIL	Power Exchange of India Limited
RPC	Regional Power Committee
STU	State Transmission Utility
STOA	Short Term Open Access
TTC	Total Transmission Capability
TANTRANSCO	Tamil Nadu Transmission Corporation Limited

UI	Unscheduled Interchange
UPPCL	Uttar Pradesh Power Corporation Limited

Connectivity Regulation	Central Electricity Regulatory Commission, Grant of Connectivity, Long-term Access and Medium-term Open Access in Inter-state Transmission and related matters Regulation, 2009
Grant of Regulatory Approval	Grant of Regulatory Approval for execution of inter-state Transmission Scheme to CTU Regulation, 2010
IEGC Regulation	Indian Electricity Grid Code Regulation, 2010
Sharing Regulation	Central Electricity Regulatory Commission, Sharing of Inter-state Transmission Charges and losses, Regulation, 2010
Tariff Regulation	Central Electricity Regulatory Commission, Terms and Conditions of Tariff Regulation, 2009

1. EXECUTIVE SUMMARY:

1.1 Transmission infrastructure is backbone for operation of a competitive electricity market. The objectives of Electricity Act,2003 like taking measures conducive for development of electricity industry, promoting competition therein, protecting interest of consumers and supply of electricity to all areas require existence of a policy framework conducive to development of a robust Inter-State Transmission System(ISTS).It would be possible to achieve ultimate objective of a competitive power market wherein cost of power is same at all nodes i.e. one Market Clearing Price (MCP) for the whole market with a well developed transmission system.

1.2 After implementation of Electricity Act,2003 and Open Access in Inter -state Transmission system , for development of a robust transmission system in the country ,Commission in 2009 and 2010 initiate new Regulatory mechanism through its various regulations like Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access to the inter-State Transmission and related matters) Regulations, 2009 (Connectivity Regulations) , Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 (Sharing Regulations) and Regulations for Grant of Regulatory Approval for execution of Inter State Transmission schemes to CTU .

1.3 Commission vide its two orders issue in March,2010 and Feb,2011 grant approval for Eleven High Capacity Transmission corridors for evacuation of power of Generation projects of IPPs(Independent Power producers) from Surplus areas of the Country to deficit areas on the target region basis.

1.4 The progress of these IPPS projects was affected due to various reasons like delay in land acquisition, statutory clearance and fuel tie up . Due to issues related to case – I bidding not many distribution companies have tied up their power requirement from these generating stations.

1.5 Central Electricity Regulatory Commission had received views of System planners namely CEA and CTU and System Operator on the Connectivity Regulations. CTU and CEA raised concern in regard to the present mechanism of treating Connectivity and Long Term Access separately. They also raised concern that there being no liability for payment of transmission charges associated with Connectivity and liability to pay transmission charges being linked to Long Term Access (LTA), some of the generators were seeking LTA for a quantum much less than their Connectivity. Further, as these generators do not have any firm beneficiaries, it is difficult to plan transmission system. POSOCO filed a petition in September, 2012 before the Commission, seeking amendment in Connectivity, Long Term Access and Medium Term Open Access Regulations stating that some operational problems were being faced due to provisions in these Regulations. It is noteworthy to see that CEA and CTU are moving ahead from their initial position of requiring firm beneficiaries at least five years in advance to a more market friendly approach and mooted concept of General Network Access (GNA) which has lot of merits. While taking cognizance of their concerns, it became apparent that this issue has wider implications and solution should not be limited to address immediate problem only.

1.6 It was observed that this issue raised by planner and system operator on connectivity and Long term access is not a standalone issue but it has various dimension covering the whole value chain of transmission. Any regulatory decision in this regard is going to affect all part of the power sectors as transmission is the vital link between generation and distribution. The issue need to be looked with wider perspective encompassing transmission planning, execution, transmission cost allocation and operational issues like congestion.

1.7 The role of transmission system as provider of economic benefit at the time of generation evacuation schemes gradually move to add reliability benefit when regional and inter regional transmission planning was done. As explained by the North American Reliability Council (NERC 1997), transmission network are the "principal media for achieving reliable electric supply". Now after deregulation of Generation and provision of open access, transmission is playing the role of market enabler, to fulfill this role effectively it need a reform push to achieve the objective of 24x7 power supply at affordable rate.

1.8 Wider consultation on all issues related to transmission planning, execution, allocation or sharing of transmission cost and transmission corridor allocation appears essential. Staff of the Commission therefore brings out this concept paper for seeking views/suggestions of the stakeholders on all these issues .CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 which is under review as per directions provided in Sharing Regulations and issues raised by stakeholders, draft amendment has already been brought out for soliciting views of stakeholders. This concept paper integrates Sharing Regulations with Planning Code under Indian Electricity Grid Code (IEGC) and Connectivity Regulations. Implementation of proposals contained in this concept paper would call for amendments in IEGC, Connectivity Regulations and Short Term Open Access Regulations.

1.9 The staff paper after covering background of the issue, existing Regulatory framework, and Issues concerning stakeholders tried to formulate the problem and its solution.

1.10 After proposing adoption of new planning methodology for planning of Inter State Transmission System in a more coordinated manner, staff paper is suggesting two alternatives for providing connectivity and long term access to the users.

1.11 First alternative is based on international practices of deep and shallow connection offers a banquet of products and second alternative is based on General Network Access (GNA) which was being discussed by CEA and CTU.

1.12 As the issue of relinquishment or shifting of target region for long term access by Generator is an area of concern for Central transmission Utility (CTU), new formulation in regards to EXIT charges is proposed under both alternative.

1.13 The issue of utilization of transmission charges collected through e-bidding and congestion revenue and transmission capacity allocation for power market is discussed. Alternative of participation of power exchanges in e-bidding of transmission corridor is also discussed.

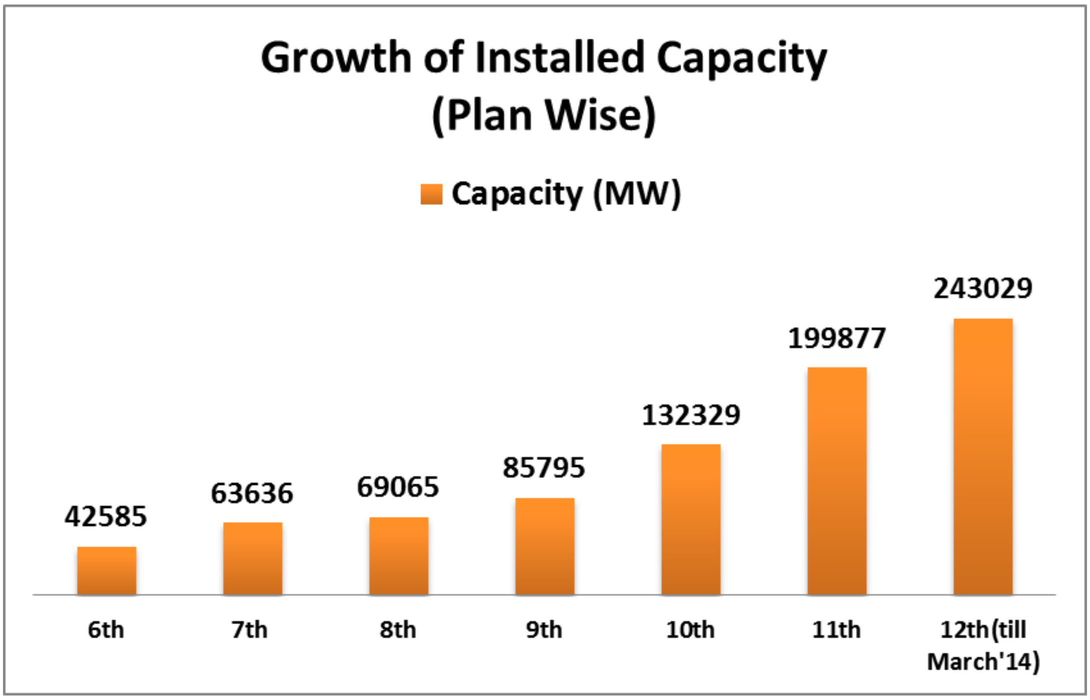
1.14 The issues discussed in this concept paper needs wide discussion involving not only the statutory organisations and the stakeholders in power sector but also the Academia including IITs, NITs, IIMs, etc.. Staff in the Commission is keenly looking forward to receive valuable suggestions, inputs and guidance from all concerned.

"We cannot solve our problems with the same level of thinking that created them"
― *Albert Einstein*

2. BACKGROUND:

2.1 Transmission infrastructure is backbone for operation of a competitive electricity market. Electricity Act,2003 ushered an era of de-licensed generation and Open Access. Transmission is the link which synergies these two. However achieving synchronization between a licensed activity of transmission and an open market and de-licensed generation coupled with Open Access poses a few challenges as compared to the planning carried out with identified location and capacity of ISGS and their identified beneficiaries.

2.2 The cost of transmission system being significantly less than that of cost of generation, growth of transmission system should match with the growth of generation capacity in the country and ideally it must be ahead of generation both in time and capacity to avoid congestion or bottling up of power. Efficient operation of transmission system in terms of providing reliability, avoidance of disturbance and less transmission losses also requires continuous strengthening of transmission system.



(Source: CEA Executive Summary, March,2014)[1]

Figure 1: Plan wise Installed Capacity

2.3 The Inter-State Transmission System, which is the integrating backbone of the India's vast National Power Grid has achieved tremendous growth. Central Electricity

[1] http://www.cea.nic.in/reports/monthly/executive_rep/mar14.pdf

Authority Report indicates that from the end of Sixth Plan (1985) till March'14, length of transmission lines of 220kV and above in the country has increased from 52,000 ckm to 3,02,548 ckm and transformation capacity has increased from 46,621 MVA to 5,00,846 MVA. In central sector during last five years many 765 kV lines had been constructed.

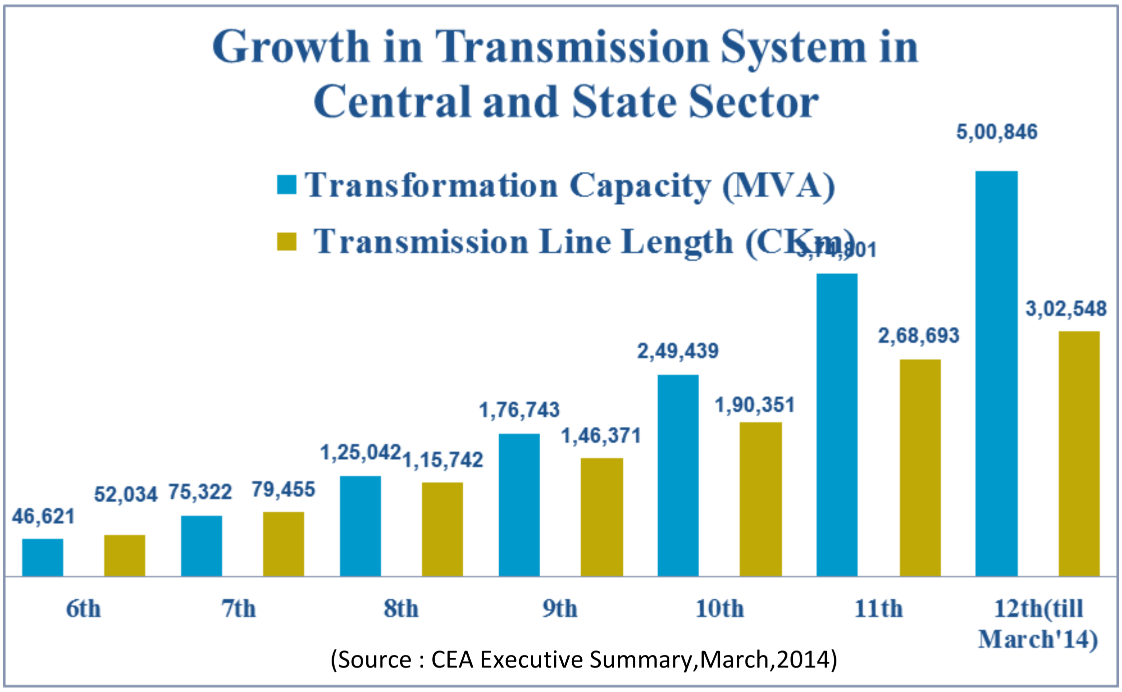


Figure 2: Growth in Transmission System in Central and State Sector

2.4 However, development of transmission system must match with generating capacity on one side and growing demand on the other side. With Open Access in transmission, the role of transmission has changed from a mere infrastructure to an enabler in operation of a competitive power market.

2.5 While there has been a marked increase in growth of central sector transmission system and transformation capacity during the 11th and 12th Plan, transmission congestion in some parts of the grid evident during the last few years underlines the need for emphasis on development of adequate transmission system. With emphasis of Government on higher growth in Indian economy and improving financial health of DISCOMs, leading to higher degree of satisfaction of demand for electricity, inadequacy in bulk transmission system should not be a constraint in the growth of power sector which in turn impacts country's economy.

2.6 Fund requirement for the transmission sector during 12th Plan[2] period is about Rs.233914 Cr. Detail is enclosed as Annexure- I It is necessary that such a large investment is done with prudence and benefits are optimized.

[2] http://www.cea.nic.in/reports/articles/ps/funds.pdf

2.7 With de-licensing of generation and unbundling of State Electricity Boards, uncertainty in generation and demand is already evident i.e. at both sides of transmission. At this stage looking into the issue of transmission planning simply as a tool to provide transmission access to generating stations being developed by IPPs may not be right. Transmission planning needs to be taken as integrated resource planning and there should not be any policy or regulatory uncertainty which comes in the way of achieving an important objective of Electricity Act,2003 i.e. development of electricity industry. This cannot be achieved sans a robust transmission network linking de-licensed generators to open access customers in any part of the country. In this regard any attempt to bind or limit the "choice" by restricting the type of access to only long-term access through transmission planning, transmission cost allocation or system operation perspective would not be fulfilling the true objective of restructuring of Indian power sector.

2.8 Though a few steps taken by Central Commission in the last three years provided solution for time being, a rush of IPPs in post power market era of excessive profit in power generation brought to the fore difficulty which calls for a review of whole value chain of transmission system in the country.

2.9 Although National Electricity Policy and Tariff Policy provide guiding principles for development of transmission system, differing pace of development and uncertainties associated with three different segments of power sector i.e. generation, transmission and distribution is posing fresh challenges in transmission planning and implementation of transmission projects.

2.10 The development of transmission system is dependent on four key activities - basis of transmission planning, manner of implementation of transmission projects, basis of allocation of transmission cost and operation of transmission system in real time.

2.11 Central Electricity Regulatory Commission made timely effort and took necessary regulatory steps for development of a robust transmission network needed for a competitive power market in a timely manner and for appropriately allocating transmission cost to users. The actions started in 2004 through Regulations for Open Access in ISTS network, Staff paper on "Arranging Transmission for New Generating Stations , Captive Power Plants and Buyers of Electricity "in July,2008[3]. In 2009, some of these concepts were incorporated in Tariff Regulations and another comprehensive regulation namely Connectivity Regulation was brought out. Short Term Open Access Regulations and Power Market Regulations were brought out in 2008 and 2010 respectively. As the issue of IPP without beneficiary was posing a situation wherein it was possible that a significant generating capacity could have

[3] http://www.cercind.gov.in/July08/Public-notice-for-staff-papers.pdf

faced problem in evacuation of power, Central Commission brought out two Regulations namely Regulations for Regulatory Approval for execution of Inter State Transmission scheme to CTU Regulations, 2010, and Sharing Regulations, 2010.

2.12 In this endeavor, Commission followed a process for framing of Regulations through detailed discussion with stakeholders for about two years. Commission desires that the progress already achieved through these Regulations should not, in anyway, be diluted by some hurdles or temporary setbacks and solution for present problems be found with active participation of all.

2.13 The uncertainty in location, timeframe and fuel availability for generating units and non-availability of identified beneficiaries in view of very few case- 1 or Case- 2 bids has reversed the scenario. Probability of unutilised transmission capacity has increased as more and more generating capacity is facing problem in regard to availability of fuel and statutory approvals like environment clearance. The rates for electricity in power market are also showing downward trend. The increasing penetration of renewable is also posing new challenges in planning of transmission system as well as operation of Grid.

2.14 During last four years through interaction with various stakeholders in the form of consultations at various fora, petitions filed by generating companies either for exit option thereby seeking exemption from payment of transmission charges or congestion related issues, court cases and congestion being faced by some of the customers, Commission recognised need for urgent attention to transmission planning and development.

2.15 Even in an economic and efficiently designed transmission system, the probability of congestion cannot be ruled out if desired objective is to be conservative in investment. However, if congestion is due to some short sighted commercial decision of generation and drawee utility, impact of congestion is borne by customers in the form of higher cost of power or power-cuts.

2.16 It is noted that most of the concerns expressed by central planning agencies and system operator stem from following three issues i.e. connectivity without any liability to pay transmission charges, lesser requisition of LTA and non-declaration of drawal requirement. Transmission congestion is only a by-product of these. It needs to be examined as to how these issues are affecting transmission planning and whether design of transmission cost allocation is affecting the planning adversely.

2.17 While central planning agencies expressed difficulties in transmission planning, system operator expressed difficulties in system operation due to increasing short term power transactions. Generating companies and consumers are facing recurrent congestion and desired growth of power market is hampered due to the fact that consumers are not sure that transactions through power exchange would materialize or not .

2.18 There is need to take a long term view on all these issues and it was noted that problem needs to be addressed in an effective manner because investments in generation as well as transmission are long- term investments and Regulatory certainty is required over a longer time horizon. Therefore, instead of any short-term changes, it is considered appropriate to review and address the related issues in regard to the following:

a. Transmission planning process and Grid Code
b. Connectivity, Long Term Access and Medium Term Open Access Regulations.
c. Congestion management.
d. Integration of transmission cost allocation and transmission planning.
e. Transmission corridor allocation for short term transactions in power exchanges.

2.19 Thus in brief there is a need to initiate debate on following Transmission related issues:

a. Whether integrated and coordinated transmission planning is required to adopt itself to new market reality or LTA based planning is to be continued?
b. Which cost is to be assigned to Generator?
c. How to handle Exit and delay in commissioning of projects?
d. Whether transmission planning needs Regulatory Guidance Flexible access or fixed access (GNA)

3. EXISTING REGULATORY MECHANISM

"The formulation of the problem is often more essential than its solution, which may be merely a matter of mathematical or experimental skill." — Albert Einstein

A closer look at the problem as well as regulatory process in regard to transmission planning and access to Inter State Transmission System would help in search for appropriate solution(s). Since the issues now being underlined by central planning agencies regarding difficulties in planning and execution of transmission projects are almost similar to the issues brought out in 2008, it is prudent to look at all the relevant regulatory reforms initiated since 2008 particularly in transmission sector, their objectives and assess the outcome.

3.1 ELECTRICITY ACT, 2003

3.1.1 ROLE OF CTU IN PLANNING OF ISTS

Section 38 (2) of the Electricity Act, 2003 specifies role of CTU as follows:

The functions of the Central Transmission Utility shall be -

to undertake transmission of electricity through inter-State transmission system;

to discharge all functions of **planning and co-ordination** relating to inter-State transmission system with -

(i) State Transmission Utilities;

(ii) Central Government;

(iii) State Governments;

(iv) Generating companies;

(v) Regional Power Committees;

(vi) Authority;

(vii) Licensees;

(viii) Any other person notified by the Central Government in this behalf;

to ensure development of an efficient, co-ordinate and economical system of inter-State transmission lines for smooth flow of electricity from generating stations to the load centers;

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:

3.1.2 Role of STU

Similar functions are provided for State Transmission Utility (STU) under Section 39(2) of the Act

3.1.3 Duties of Generating Companies

In the process of transmission planning, the duties of Generating companies are defined under Section 10(3) of the Act as under

(1) ....

(2) ....

(3) *Every generating company shall -*

(a) submit technical details regarding its generating stations to the Appropriate Commission and the Authority

(b) co-ordinate with the Central Transmission Utility or the State Transmission Utility, as the case may be, for transmission of the electricity generated by it.

Hence the Electricity Act, 2003 recognizes that transmission planning process is a coordinated activity in which CTU and STU need to coordinate among themselves in addition to coordination with Authority, Licensees and Generating companies also need to coordinate with CTU or STU for transmission of electricity generated by them.

3.1.4 Approach laid down in National Electricity Policy and Tariff Policy in regard to Transmission Planning

It was realized that after implementation of Electricity Act, 2003, the transmission planning activity will face new challenges under open access regime and it needs to respond to the challenge in a pro-active manner rather than in a reactive manner in which transmission system was planned after firming up contracts. This found a place in the National Electricity Policy (2005) and Tariff Policy (2006) as under:

3.1.5 National Electricity Policy

Network expansion should be planned and implemented keeping in view the anticipated transmission needs that would be incident on the system in the open access regime. Prior agreement with the beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consultation with stakeholders and taking up the execution after due regulatory approvals."

3.1.6 Tariff Policy

In view of the approach laid down by the NEP, prior agreement with the beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consonance with the National Electricity Plan and in consultation with stakeholders, and taking up the execution after due regulatory approval."

3.2 Grid Code and Transmission Planning

As development of ISTS required comprehensive transmission planning, Central Commission incorporated guidelines for planning of ISTS in Indian Electricity Grid Code.

3.2.1 Part 3 of Central Electricity Regulatory Commission (Indian Electricity Grid Code) 2009 provides for planning code for inter State Transmission System.

Part3: Planning Code for inter-State transmission

This Part provides the guidelines to be adopted in the planning and development of bulk power transfer and associated ISTS. The Planning Code lays out the detailed ***information exchange*** *required between the planning agencies and the various participants of the power system for load forecasting, generation availability, and power system planning etc. for the future years study. The Planning Code stipulates the various criteria to be adopted during the planning process.*

3.2.2 Regulation 3.4 (d) of IEGC provides as under:

All, STU and Users will supply to the CTU, the desired planning data from time to time to enable to formulate and finalize its plan.

3.2.3 The detailed provisions in the Grid Code for planning of Inter -State transmission system are given at **Annexure- II**

3.2.4 As there are provisions for information exchange, it is clear that transmission planning process is a transparent participative process involving all users of the ISTS. **To achieve the objective of a robust and reliable transmission process, it is necessary that all users should submit their requirement for usage of ISTS.** It is necessary that the information exchange process needs to be made more specific so that while planning the system, planning agencies have a fair idea about requirement for usage of ISTS in at least a 5 year time horizon. As this is based on assumptions and forecasting, certain deviations are likely to be there when these system are executed, but this is bound to be there in any system where planning is done in such a manner.

3.2.5 Also Grid Code stipulates that transmission planning would take care of the need of Open Access and Renewables.

3.3 CERC Staff Paper on 'Arranging transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity' (July, 2008)

3.3.1 The real challenge for integrated transmission planning started to surface with the emergence of Independent Power Producers (IPPs) and Open Access customers. Realizing the benefits of Open Access in Inter-State transmission system introduced since 2004, generating stations were set up in different parts of the country with no identified long-term buyers. The uncertainties about location and commissioning schedule of such generating stations and possibilities of customers being in any part of the country, created a situation where traditional transmission planning process which was based on firm source – sink relationship, found it difficult to cope with this new situation.

3.3.2 Taking cognizance of need for development of transmission system, CERC through the staff paper emphasised that there is a need to quickly develop the associated transmission system:

1. *"Traditionally in India, new generating stations were in public sector and the associated transmission systems were developed either under the aegis of vertically integrated State Electricity Boards (SEBs) or through Central Public Sector Undertakings (CPSUs) under the overall coordination of Central Electricity Authority (CEA). Although generation was opened up for private sector way back in 1992 but of late private players have become active and started entering the generation sector in a big way lining up massive investments.*

2. *Powergrid, the CTU, has indicated that they have approved 26 cases of associated transmission systems for new generating stations adding to about 22,698 MW for long-term usage under CERC Open Access Regulations, 2004. Another 27 applications aggregating 11,187 MW generating capacity are under finalization and 48 cases amounting to 48,324 MW are under processing for creating of associated transmission systems. It is indeed a heartening development – a tangible outcome of various reform and market development initiatives – that beckons us to quickly build the associated transmission system for delivery of power to the intended destinations. Whatever be the commercial arrangements for sale of power, it is necessary to embrace all new generating stations in the transmission planning process so as to ensure timely evacuation of power matching with the generation addition program, through smooth coordination and practical commercial arrangements.*
3. *It has been brought to our notice by Powergrid that in many instances the developers of large generating stations have approached for creation of transmission facilities at too late a stage when adequate time is not available to identify system strengthening requirement and for its timely implementation. Powergrid feels that they should be given 3-4 years time in normal cases and one year extra for the NE region.*
4. *Presently, a generator wanting to arrange transmission is required to give information about the beneficiaries along with their allocations for the purpose of transmission planning. However, it has been experienced that the generating companies are finding it difficult to indicate the beneficiaries upfront on two accounts; firstly due to requirement for the distribution companies to procure power on the competitive basis and therefore neither the buyers/beneficiaries are able to offer commitment nor generating companies are able to tie up such commitments at the time of preparation of projects; and secondly because a number of generators are interested in setting up merchant power capacity, at least in part of the plant capacity. In the absence of such information, the generators are finding it difficult to approach Powergrid with formal application and at the same time it becomes difficult for Powergrid to process such applications without identifying the beneficiaries. This is leading to delays in applying/processing of request. Therefore, there is a need to evolve a pragmatic*

approach, which gives adequate comfort to the applicant in achieving various milestones for implementation of generation projects as well as ensures timely execution of activities to be undertaken for implementation of the required transmission scheme.

Powergrid has also pointed out that private developers are under-stating their requirement for power evacuation with a view to reducing their liability of sharing transmission charges. After getting grid connectivity and access to the market in this manner, they may apply for additional evacuation of power under short-term open access regulations where the transmission charges are quite nominal. We cannot allow them to game for exploiting the differential between normal transmission tariffs and short-term transmission tariffs to their advantage at the cost of optimum and planned development of transmission."

3.3.3 Thus, if we compare the position occurring at present or the issues raised by CTU, these are almost similar to the issues raised during 2008, at the time of preparation of earlier staff paper.

3.4 CERC TARIFF REGULATION, 2009

To resolve the problems being faced by transmission planners, generators and users of the transmission system, Central Commission took an initiative through Tariff Regulations, 2009 by specifying basis of sharing of transmission charges of existing ISTS by a new generator till the time the transmission system for it was under development, through **Regulation 33(2)** as under:

33 Sharing of Transmission charges:

1. *The following shall be added up to arrive at the regional transmission charges payable for a month by the users of the concerned regional (common) transmission system:*

   a) ....

   b) ....

2. *The above regional transmission charges (grossed up) shall be shared by the following*

   i)

   ii)

(iii) Generating companies owning generating stations connected to inter-state transmission system in the region, but for which the associated transmission system has not been fully commissioned for any reason, in proportion to the gap (in MW) between the generating capacity commissioned up to the end of the month and the capacity for which the designated associated transmission system has been commissioned up to the beginning of the month.

3.5 PROCESS FOR DEVELOPMENT OF TRANSMISSION SYSTEM

3.5.1 When an application for use of inter-State transmission system is received, the sequence of activities which take place is given below:

(i) Assessing adequacy of existing network for evacuation of power from Generator.

(ii) Planning of additional network, if required, through a consultative process.

(iii) Approval of the proposed transmission system from beneficiary for assuring payment of transmission charges. If no beneficiary is identifiable, Regulatory approval is needed. While granting approval, the Commission needs to see cost-benefit and seek an assurance for servicing the cost of transmission.

(iv) Execution of transmission scheme needs to be matching with generation project(s) so as to avoid bottling up of generation and non-utilisation of transmission asset.

(v) Allocation of transmission cost in a fair manner.

3.6 CERC REGULATIONS ON TRANSMISSION

For achieving these, three important Regulations were framed. These basically covered assessing the quantum of Transmission Service to be provided, approval process and transmission cost allocation through the following.

i. Connectivity and Grant of Long term Access and Medium Term Open Access Regulations, 2009

ii. Grant of Regulatory Approval for execution for inter-State transmission scheme to CTU Regulations, 2010.

iii. Sharing of Inter-State transmission charges and losses Regulations, 2010

The linkage of these three Regulations needs to be described for proper understanding and appreciation of the issues.

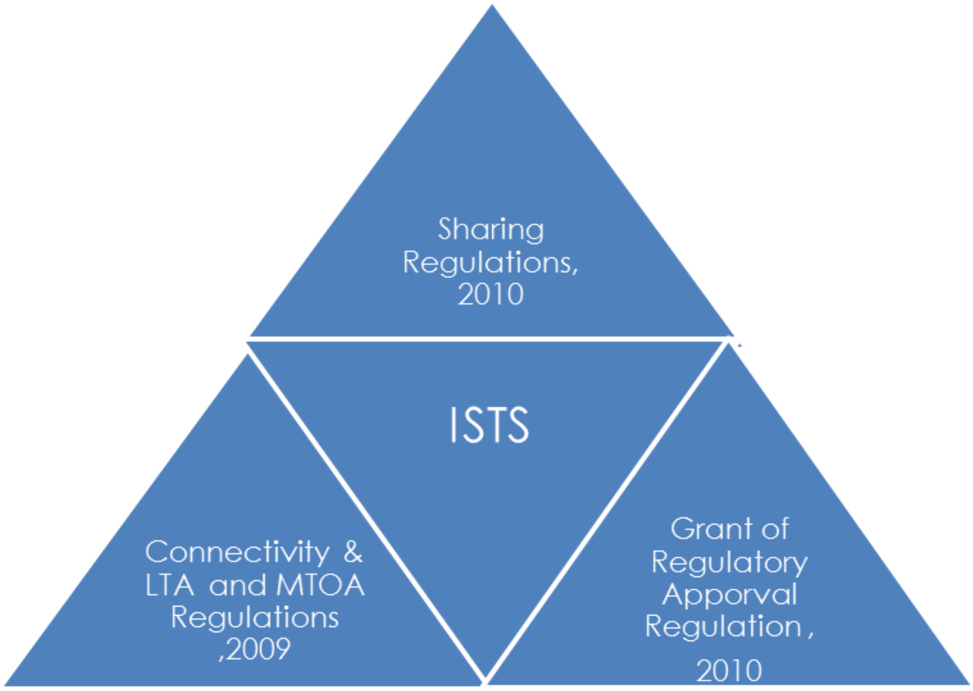


Figure 3: CERC Regulations on Transmission

3.7 CENTRAL ELECTRICITY REGULATORY COMMISSION (GRANT OF CONNECTIVITY, LONG-TERM ACCESS AND MEDIUM-TERM OPEN ACCESS TO THE INTER-STATE TRANSMISSION AND RELATED MATTERS) REGULATIONS, 2009

3.7.1 To implement suggestions given in staff paper of July, 2008, Commission formulated draft Regulations on Grant of Connectivity, Long-term Access and Medium-term Open Access to the inter-State Transmission and related matters (referred to as Connectivity Regulations) on 2.3.2009. After due consultative process the Regulations were finalized on 7.8.2009. The Regulations came into effect after detailed Procedure of Central Transmission Utility (CTU) was approved by the Commission i.e. 01.1.2010

3.7.2 The Connectivity Regulations provide for Connectivity and Long Term and Medium Term Access to ISTS. On the basis of this, CTU formulates the transmission system required to be developed either as evacuation plan or as system strengthening of Regional Grid.

3.7.3 Connectivity Regulations incorporated some of the suggestions of staff paper of 2008 like grant of LTA to target region in the event of generator not being able to identify beneficiaries at initial stage.

3.7.4 As most of requests for Connectivity and Long Term Access were from IPPs, initially they did not have identified beneficiary(s). Hitherto prevailing procedure of getting the transmission system approved by Standing Committee on transmission planning, getting approval in Regional Power Committee and signing of Bulk Power Transfer Agreement (BPTA) by beneficiaries was not feasible in such a scenario.

3.7.5 In the Connectivity Regulations, Connectivity and grant of LTA were segregated (although applicant was at liberty to seek both simultaneously). Connectivity was provided as a separate product to enable generating stations to know in advance, the connection point up to which they need to build their dedicated line.

3.7.6 Also it was categorically mentioned there that no power can be transacted without obtaining open access of one type or the other.

Regulation 8(6)

The grant of connectivity shall not entitle an applicant to interchange any power with the grid unless it obtains long-term access, medium-term open access or short-term open access.

3.7.7 A provision was also made that dedicated line upto CTU point shall be made by generator. Thermal generators having capacity of 500 MW and above and Hydro generators of 250 MW and above, shall not be required to construct dedicated line:

Regulation 8(8):

An applicant may be required by the Central Transmission Utility to construct a dedicated line to the point of connection to enable connectivity to the grid:

Provided that a thermal generating station of 500 MW and above and a hydro generating station of 250 MW and above, other than a captive generating plant, shall not be required to construct dedicated line to the point of connection and such stations shall be taken into account for coordinated transmission planning by the Central Transmission Utility and Central Electricity Authority.

3.8 Central Electricity Regulatory Commission (Grant of Regulatory Approval for execution of Inter-State Transmission scheme to Central Transmission Utility Regulations, 2010)

3.8.1 In May, 2010, Commission brought out regulations for grant of Regulatory Approval for execution of ISTS by CTU

3.8.2 The objective of the Regulations, as preamble of the Regulations, is as under:

The Central Transmission Utility has been vested with the functions under sub-clause (c) of sub-section (2) of Section 38 of the Electricity Act, 2003 (the Act) to ensure development of an efficient, co-ordinated and economical system of inter-State transmission lines for smooth flow of electricity from the generating stations to the load centers. Para 5.3.2 of the National Electricity Policy notified by the Central Government under Section 3 of the Act vide Resolution No.23/40/2004-R&R(Vol.II) dated 12.1.2005 provides that "network expansion should be planned and implemented keeping in view the anticipated transmission needs that would be incident on the system in the open access regime. Prior agreement with the beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consultation with stakeholders and taking up the execution after due regulatory approval." The Central Commission which has been vested with the power under clause (c) of sub-section (1) of Section 79 of the Act to regulate the inter-State transmission of electricity is making these regulations to streamline the procedure for according regulatory approval to Central Transmission Utility for network expansion in consonance with the National Electricity Plan.

3.8.3 In this regard, it is clarified that the objective of the Regulations is to facilitate adequate augmentation of transmission system commensurate with the addition of generation capacity. The mandate for network expansion by Central Transmission Utility specified in the National Electricity Policy has already been underlined.

3.8.4 The purpose of these regulations is to facilitate execution of the transmission scheme identified by the CTU, in time, so as to ensure evacuation of power from the planned generation capacity addition as well as to ensure smooth flow of electricity in the grid by strengthening the existing transmission system. However, delay in execution of the transmission schemes due to procedural delay in having prior agreement with all the beneficiaries cannot be ruled out. In such cases, regulatory approval by the Commission, in accordance with the spirit of the National Electricity Policy, would facilitate timely execution of the schemes.

3.8.5 The origin of these Regulations stems from the fact that to develop evacuation schemes for projects of Sasan and Krishnapatnaam UMPPs, it took long time to seek approval of the beneficiaries even when the beneficiaries were already identified. The composition of scheme and segregation of scheme into transmission system required for evacuation of generation and system strengthening scheme took almost 2 years to finalize.

3.8.6 Many IPPs were coming in fuel rich areas like Eastern Region and Central India and also in coastal areas based on imported fuels. Most of these generating stations did not have identified beneficiary and sought Long Term Access through Inter-State Transmission System. In accordance with the concept of "Target Region" based on Load Generation balance scenario and Electric Power Survey of Central Electricity Authority, CTU formulated transmission system for these generating stations. All these transmission schemes were discussed and concurred in Standing Committee for Transmission System planning. However, in the absence of identified beneficiaries, it is difficult to get Bulk Power Transmission Agreement (BPTA) signed and till these are signed, it is difficult to take investment decision as recovery of transmission charges through tariff needs to be ensured.

3.8.7 Therefore, Commission formulated regulations in accordance with the National Electricity Policy specifying the basis of determination of transmission charges and its recovery as under:

"7. Recovery of charges of approved transmission Scheme

(1) The transmission tariff of the ISTS Scheme approved by the Commission under Regulation 8 of these regulations shall be determined in accordance with the prevailing regulations on terms and conditions of tariff specified by the Commission under Section 61 of the Act.

(2) The tariff of the ISTS Scheme determined in accordance with clause (1) of this regulation shall be borne by the users of the Scheme.

(3) The method of sharing of transmission charges among the users of the ISTS Scheme shall be based on the sharing methodology as may be specified by the Commission from time to time.

3.8.8 Thus the CTU or any other transmission licensee developing ISTS was assured that transmission charges shall be computed in accordance with CERC Tariff Regulations and the same shall be shared in accordance with sharing methodology specified by the Commission.

3.8.9 However mere assurance that tariff would be granted would not be sufficient to take care of interest of all users of transmission system. For this a fair transmission cost allocation process needed to be developed to take care of interest of existing as well as future users. For this, two step procedure was adopted.

3.8.10 Before commissioning of generating stations, the applicant of LTA(i.e Generator) was made responsible for payment of transmission charges and once generating station gets commissioned, responsibility of payment of transmission charges was shifted to beneficiary(s). Till identification of beneficiaries, it shall be the responsibility of Generating Company (LTA applicant) to pay transmission charges.

3.9 Transmission Charge Allocation

3.9.1 For development of fair allocation of transmission charges i.e. how the transmission charges of ISTS shall be shared, Commission took initiative to implement the mandate of National Electricity Policy .

3.10 PROVISIONS OF THE NATIONAL ELECTRICITY POLICY ON TRANSMISSION

Table 1: Provisions of the National Electricity Policy on Transmission

Para No.	Provision
5.3.2	**** Network expansion should be planned and implemented keeping in view the anticipated transmission needs that would be incident on the system in the open access regime. Prior agreement with the beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consultation with stakeholders and taking up the execution after due regulatory approvals.
5.3.5	**** To facilitate orderly growth and development of the power sector and also for secure and reliable operation of the grid, adequate margins in transmission system should be created. The transmission capacity would be planned and built to cater to both the redundancy levels and margins keeping in view international standards and practices.
5.3.5	**** To facilitate cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC. The tariff mechanism would be sensitive to distance, direction and related to quantum of flow.

3.11 PROVISIONS OF THE TARIFF POLICY TRANSMISSION PRICING

Para No.	Provision
7.1(3)	Transmission charges, under this framework, can be determined on MW per circuit kilometre basis, zonal postage stamp basis, or some other pragmatic variant, the ultimate objective being to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system. The overall tariff framework should be such as not to inhibit planned development/augmentation of the transmission system, but should discourage non-optimal transmission investment

7.1(4)	In view of the approach laid down by the NEP, prior agreement with the beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consonance with the National Electricity Plan and in consultation with stakeholders, and taking up the execution after due regulatory approvals

Table 2: Provision of Tariff Policy on Transmission Pricing

3.11.1 Efforts to formulate methodology for sharing of transmission charges of ISTS were initiated way back in 2007 and following papers, orders, etc., were issued:

1. Discussion paper on 'Approach for Sharing of Transmission Charges and Losses' February,2007
2. CERC Order dated 2.7.2007 and 28.3.2008 in Petition No. 85/2007
3. Staff paper 'Arranging Transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity', July,2008.
4. Approach paper on "Sharing of Transmission Charges, 15.5.2009 *(The issue of transmission pricing was discussed in this Approach paper)*
5. Draft Regulations on Sharing of Inter State Transmission Charges and Losses-Feberuray,2010
6. Sharing of Inter-state Transmission Charges & Losses Regulations (15.6.2010)

3.11.2 Salient points in the Approach Paper on Sharing of Transmission Charges (May, 2009) are quoted below:

FORMULATING PRICING METHODOLOGY FOR INTER-STATE TRANSMISSION IN INDIA

- *Postage stamp method is more suited when the geographical area in consideration / the electrical network is relatively small, flows are simple and do not cause large externalities (parallel flows) for intervening / electrically contiguous regions and priority is accorded to simplicity and social acceptability over economic efficiency. In the changed scenario regional postage stamp method is beset with problems of pan-caking of* *transmission charges which deters economy trades across regions and hence prevents competition and efficient use of resources. Further, regional postage stamp method does not satisfy the efficiency requirements of the National Electricity Policy, which require transmission prices to be distance and direction sensitive, independent of Bulk Power Transmission Agreements and reflect the utilization of the network by each network user.*

- *The generators will be required to forecast their levels of generation during seasonal "peak" and "other than peak" periods specified by the NLDC a year in advance. Similarly the demand customers will be required to forecast and submit their demand during seasonal "peak" and "other than peak" periods specified by the NLDC* ***. This is called the chargeable capacity.*** *Transmission charges indicated in* ***Rs/MW/month are multiplied by the chargeable capacity to determine monthly charges.***

- *In the implementation of Point of connection Tariffs – such as those determined using MP(Marginal Partcipation) method – the need for separate charges for long term and short term open access can be obviated.* ***Further, the need for Bulk Power Transmission Agreements (BPTA) specifying destination of the power flows as a prerequisite for building new transmission lines or systems is also obviated****. However, the generators and demand customers will be required to sign alternate commercial agreements – referred to as Connection and Use of System Agreement (CUSA) in this document. The CUSA will specify the commercial arrangements between the providers of the transmission system and the system users in terms of commissioning schedules, performance obligations and guarantees, default provisions, etc.* ***In other words, apart from the need for specifying the destination of power for a generator and the source of power for a demand user, other key provisions of a BPTA would be retained in the CUSA****. New lines would now be built upon regulatory approval based on plans prepared by the CEA (including the perspective plans) and CTU (for specific projects). This is* *expected to address a key concern regarding the development of transmission systems at present.*

- *The rapidly developing transmission system at the inter-state level has been a key factor in the evolution of power trading in the country since the Electricity Act, 2003 came into effect. More recently, operations of power exchanges have also been greatly facilitated by the increasing depth of the transmission network.*
- *In several instances the present regional pricing system acts as an impediment in this regard since superimposition of the regional pricing system on the national transmission network leads to artificial burdening of some of the network users and makes several commercial transactions uneconomical*

- *In many of the cases the location of the power plants would result in transmission of power over long distances using the ISTS. In most of the cases the power will flow across the existing regional boundaries. Almost by definition the merchant power plants cannot specify the final point of contractual delivery in advance. This has indeed been a key point of contention, and the proposed pricing framework would need to address the issue directly.*
- The introduction of Merchant power would require a change in these arrangements since for a significant proportion of the capacity there would not be any ab-initio identification of end beneficiaries. Thus the generators would have to pay for the transmission capacity that they utilise. This modification in arrangements has already been introduced by CERC. In the absence of specific identification of beneficiaries, the generators have been asked to identify the region to which the power generated would be taken to (and the proportions in case multiple regions are involved). Even as these arrangements could serve as a stop-gap measure, they do introduce rigidities in the energy transactions along defined contractual paths, which should be avoided. Electricity, once injected in the system, follows its own flow paths based on the laws of physics, and such flows could change

substantially with load conditions. The pricing mechanisms should arguably be consistent with the laws of physics and not contracts.

- A practical issue that also needs to be considered in this context is that of ownership of the generation and transmission assets. On account of increased ownership of such assets by the private sector, there is an expected reluctance of state owned beneficiaries to fund for transmission development, unless there is a direct identified benefit for the user. In practice in a deeply meshed transmission system like in India, attribution of lines to individual users (or even a group of users in a region) is no longer possible. Power flows in one part of country could have significant impact in other parts which are in no way commercially related. Hence there is a clear need to move away from the philosophy of attribution that has been the basis for transmission system development and pricing in the past, and migrate to a framework that is more contemporary and aligned to the nature of use of the grid.

- Evolution of open access and competitive power markets has a direct bearing on the pricing of transmission services. Presently open access is organised around two basic paradigms (i) Beneficiary based system for long term use and (ii) Short Term Open Access (STOA), which can be availed for a period of up to one year. Regulations have been evolved by the CERC on the above lines. A key part of the regulations is the pricing of services, which in turn is connected to the nature of use. STOA in particular is considered, “incidental” to long term system use, utilising the redundancies and margins available on the system.
- In practice STOA is not incidental, considering the thrust of public policy on evolution of competitive and efficient energy markets. It is the backbone of trading and market operations, which have been rapidly gaining volumes as well as acceptability among users. By constraining STOA, the depth of this market is reduced, limiting potential transactions and thus affecting efficient price formation. If the transmission system access or pricing

thereof becomes a constraint, it would run contrary to the law and policy of the land.

- On the other hand, on account of STOA being considered incidental, the pricing of STOA has been limited to a fraction of the average cost of transmission services. Even these low levels are not attracted for UI and Px based transactions. Thus there is a genuine angst among the long term beneficiaries, who believe that STOA users are essentially "free riders" on the system created and/or paid for by them.
- In an economy which is electrical energy deficit, short term electricity prices are normally much higher than the long term prices of electricity. The new generators therefore would be induced not to commit to long term use of the network and to trade electricity in short term markets. Having low short term charges further accentuates the desire of the generators to forgo long term commitments. This not only leads to congestion and higher losses in the existing transmission networks but also adds considerable uncertainty in transmission grid capacity expansion thereby leading to delays in transmission investment and associated cost escalations.
- A related issue is the need for Bulk Power Transmission Agreements (BPTAs) which predicate the creation of new transmission lines for long term beneficiaries. In a system featuring increased short term and exchange based transactions, **the BPTA could act as a constraint for efficient network development and market operations. The access and pricing framework adopted needs to take into consideration this factor and, to the extent possible, obviate the need for such prior agreements in the design of the proposed arrangements.**

3.12 CERC (Sharing of Inter-state Transmission Charges & Losses) Regulation, 2010

3.12.1 In June,2010 after wide ranging and exhaustive discussion with all stakeholders and inviting comments from stakeholder and following the process of public hearing , Commission finalized Sharing Regulations. After conducting series of capacity building workshop and discussion in implementation committee, these Regulations were implemented from 1st July, 2011.

3.13 Modifications during implementation of Sharing Regulations

3.13.1 The above description clarifies that the concept behind Sharing Regulations was sharing of transmission charges based on usage. The role to be played by "Contract" was for the forecasting of injection and with-drawal for the next application period by the Designated Inter-State Customers (DIC) to project its usage of ISTS. The billing of transmission charges was to be based on approved injection and withdrawal, it was not intended to be equal to LTA. During implementation, to resolve the issue of computation for few generating stations having LTA with target region and without identified beneficiaries, LTA was taken as approved injection

3.13.2 The basic principle of usage based cost allocation was formulated under these Regulations. While implementing Regulations, certain amendment / orders were issued changing the methodology more towards billing on contracted amount of transmission service i.e. LTA. Although Point of Connection (PoC) rates were computed using actual usage, billing was done on the basis of LTA. Certain changes were also made to reduce the initial tariff shock on the beneficiaries. It was a period of transition and during this process while Generating stations not being sure that how the billing of transmission charges will be done, made request to the CTU for connectivity but as they were not sure about their beneficiary, they might have sought LTA which was less than the connectivity. This is an important issue which is now leading to difficulties in transmission planning. Although certain steps like adjustment of STOA against LTA already paid were introduced, to make seeking LTA attractive and reduce double charging, certain generators sought LTA less than Connectivity.

3.13.3 There is a disconnect between Transmission planning process and transmission cost allocation process; the planning is on the basis of peak scenarios and computation of transmission charges is on the basis of Average scenario. This needs to be addressed for the twin purpose of optimal transmission planning and simultaneously mitigating the chances of congestion in evacuation of power.

3.13.4 If one reviews the process of transmission planning for Inter-State Generating Stations (ISGS), as generator need not to pay for transmission and it was the responsibility of their beneficiaries to pay the transmission charge, the evacuation system for the generator was based on installed capacity and also took care of N-1 criteria.

3.13.5 The concept of building transmission system based on LTA and then charging generators based on LTA resulted in discouraging the generators in spelling out their true requirement to transmission system planner. Firstly the quantity was informed with presumption that the transmission system already developed by CTU would have certain margins on which they can take a free ride and pay for use in short term. Secondly, the transmission requirement was not communicated well in time; rather it was often communicated very late, and sufficient time for development/strengthening of transmission system was not available.

3.13.6 This happened because the generator was never asked as to how it is going to deliver its balance power if LTA was less than Connectivity. It was left to generator with the presumption that he was doing at its own risk. However after 4 years it has been realised that his commercial decision is creating technical problems in safe and secure grid operation. While congestion at both injection and Drawal end was experienced, too much reliance on short term transactions created problems in managing the grid effectively.

3.13.7 Again we would like to quote from Concept paper of 2008

"18. Generating companies making large investment in generating stations would not like the transmission system to become a bottleneck in evacuation of the station output. They would want an assurance in the matter on a sustained basis. Even if the size and location of a generating station and its beneficiaries are such that the incremental power flows could prima facie be accommodated on the existing system, it has still to be checked by the concerned STU/CTU that normal redundancy margins are not encroached upon in the process. This must be done sufficiently in advance, so that if the studies show any inadequacy in the system, time is available for carrying out the required augmentation. In case, this is not done in good time, the generating company may be required to restrict its generation, and it cannot claim a priority for use of the transmission system under "open access" or any other provision, particularly if the generating company itself has been negligent in the matter. "

3.13.8 Hence the idea was that the transmission system should be planned and executed in such a way that there should be no bottled up power in the system and any commercial decision taken by the generators should not become obstacle to achieve this objective. However It would be better that before reaching at any conclusion, issues raised by various agencies are discussed.

4. STAKEHOLDER'S CONCERNS

4.1 ISSUES RAISED BY TRANSMISSION PLANNING AGENCIES

4.1.1 CENTRAL TRANSMISSION UTILITY

4.1.1.1 CTU has, in its letters to the Ministry of Power, also raised similar concerns. CTU has submitted that the planned augmentation of the transmission system is done by the CTU based on the Long-Term Access sought by the entities. The grant of LTA by the CTU also brings with it a commitment to pay the transmission charges for the quantum of LTA granted. While a few players apply for LTA for their entire capacity, some of the players have sought only connectivity or LTA for part of the capacity, thereby having little or no commitment to pay for the transmission charges. From the transmission adequacy perspective, concerns have been raised by CTU, CEA and POSOCO on mere grant of connectivity to the ISTS without LTA /augmentation of the transmission system and without payment of any charges. CTU has further submitted that the existing rules also require that the generating stations approach the CTU well in advance for grant of LTA considering nine (9) months for pre-investment activities and typically thirty six (36) months completion time for transmission lines. This is not strictly adhered to by all the players, leading to a significant time interval between grant of connectivity and commencement of LTA as this would become effective only after reinforcements in the transmission system are in place. CTU has also stated that in and around Chhattisgarh, Independent Power Producers (IPPs) at JPL Tamnar (1000 MW), JSPL (270 MW), LANCO Pathadi (600 MW), ACB Ltd. (270 MW), Sterlite (1800 MW) and BALCO(125 MW) aggregating to a total capacity of 4065 MW are connected to the ISTS and are under RLDC's control area jurisdiction. These plants however have LTA for only 800 MW. Almost all these generators are transacting power through Short Term Open Access (STOA), which is administered by RLDCs as per CERC Open Access Regulations, 2008. The STOA is granted considering the spare capacity in the system. Since transmission is a lumpy investment, the spare capacity in the system would vary from time to time. If a number of generators get connected to the system and apply to RLDCs for STOA, it puts undue pressure on the last mile player viz. RLDC. This also has the potential for insecure operation of the grid. This phenomenon is going to increase day by day as more and more IPPs are getting connected to the grid without any long term Power Purchase Agreement (PPA) and LTA.

A copy of letter dated 3.1.2011 from CTU to Secretary, CERC is enclosed at **Annexure-III**

4.1.2 CENTRAL ELECTRICITY AUTHORITY

4.1.2.1 CEA has also raised a number of concerns. According to them the provision of connectivity to ISTS without any payment of transmission charges is being misused by the IPPs. The grant of connectivity does not trigger the planning process and does not result in system strengthening. The person granted connectivity has a perverse tendency to save money by not paying long term transmission charges and availing short term open access. Short term open access is granted depending on availability of margins in the ISTS and when the short term open access is denied due to transmission constraints, a lot of hue and cry is made by the IPPs. This puts pressure on the grid operator. The person granted free connectivity to the grid has a tendency to piggy ride on the grid and stress the transmission system. As was the case in the original CERC Open Access Regulations of 2004, the connectivity should be processed simultaneously with application for long term access. Further, CEA has stated that CERC modified its LTA Regulations in 2009 and ordered grant of long terms access on the basis of target regions of drawal. At least 3 years before the COD of the power plant, drawal points for 50% capacity were to be firmed up. CEA/CTU tried their best to adapt to this scenario. In the process, 11 high capacity transmission corridors were planned, out of which 9 corridors are under various stages of implementation. These corridors were planned for evacuation of power of IPPs from various generation clusters and the corridors were directed towards deficit regions / states of the country. However, long term PPAs have not been firmed up by these IPPs and there is uncertainty about the quantum of drawal by various states. The last mile planning for drawal points and STU-ISTS interface in various states have to be firmed up on urgent basis.

4.1.2.2 CEA also wrote to CERC in February, 2013 inviting attention of the Commission to Para 3.3 of the Transmission Planning Criteria of CEA which is reproduced below:

"The long term applicants seeking transmission service are expected to pose their end-to-end requirements well in advance to the CTU/STUs so as to make available the requisite transmission capacity and minimize situations of congestion and stranded asset"

4.1.2.3 Detailed explanation of Para 3.3 furnished at Para IV of Explanatory Notes to the Transmission Planning Criteria of CEA reads as follows:

"After the emergence of electricity market, there is an expectation that the planners should suo-motu plan the expansion of the transmission system based on load forecast and generation development plans without waiting for the specific information to pour in. The above expectation is based on simplistic assumption that transmission system is similar to a plug and play device or an optic fibre backbone. The fact is that transmission system is a highly tailor made infrastructure. For instance, take the case of a 3000 MW hydro generation developer who has applied for connectivity to the CTU and is expecting the CTU to take care of its transmission needs. The fact is that no serious planning or implementation is possible simply by knowing the location of a large generation project. A 3000 MW project would require ±800 kV HVDC bi-pole from Arunachal Pradesh to the load centers in NR/WR/SR and would cost about Rs. 15,000 crore. Even on the basis of target region it would be too risky to build such an expensive system. Firm knowledge of the buying DISCOMs/States based on long term PPAs is a pre-requisite to decide the landing point of HVDC bi-pole and then to branch out to various firm buyers. ***At least 85% power should be tied up in long term PPAs at least five years in advance so that transmission can be properly planned and implemented.*** *It has also to be realized that margins for short term open access are limited. This aspect has been highlighted in the preamble as well as at para 3.3 and 3.13."*

4.1.2.4 CEA has requested to take cognizance of the same and review the regulations for long term open access accordingly. A copy of letter dated 11.02.2013 Member (PS), CEA to Secretary, CERC is enclosed at **Annexure-IV**

4.2 Issues raised by System Operator

4.2.1 It was submitted by NLDC that for a number of reasons, stakeholders, who have been granted connectivity are not availing the LTA as they are able to evacuate power through medium term and short term open access. Moreover, there are instances where the generators have sought reduction in LTA which may create issues with regard to sharing of transmission charges. NLDC has suggested that it should be made mandatory for the new generators to apply for LTA corresponding to the quantum that they shall be injecting into the grid, including overload capacity. It has also been suggested that all transactions by an entity, including Long-Term with identified beneficiary, Medium Term Open Access and Short Term Open Access should be limited to the quantum of LTA availed. Accordingly, the petitioner has requested to amend the relevant provisions of the Connectivity Regulation.

4.2.2 With the development of the system, when more generation started coming to the grid, there was a concern expressed by the generators regarding tying up of contracts and identification of the buyers well in advance. They generally expressed that exercise for planning of the generation/ transmission system starts quite well in advance say upto 3 years or even more and they expect problem in identifying the beneficiary so much in advance.

4.2.3 In order to address this, necessary provisions were made in the Regulations and the first proviso to sub-regulation (1) of regulation 12 of the Connectivity Regulations provides as follows:

> "Provided that in the case where augmentation of transmission system is required for granting open access, if the quantum of power has not been firmed up in respect of the person to whom electricity is to be supplied or the source from which electricity is to be procured, the applicant shall indicate the quantum of power along with name of the region(s) in which this electricity is proposed to be interchanged using the inter-State transmission system;"

4.2.4 Thus it is possible on part of an applicant to apply for LTA even before identifying sink or source. In such a manner, the applicants can take LTA for full quantum of generation to be evacuated (including overload capacity) or power to be drawn, so that transmission system is planned accordingly and by the time, the generation comes, the additional transmission network is also ready and evacuation of power from the generating station can be ensured.

4.2.5 Another issue which was also very often highlighted by the generators was that, when they take LTA without the identified beneficiary, then at the time of evacuation of the power to new beneficiary under Short Term Open Access (STOA) they have to pay the STOA charges also in addition to LTA charges which they are already paying to CTU in view of the long term access. Thus it becomes a case of double payment.

4.2.6 This concern of the stakeholders that in the event of taking LTA they are required to pay the transmission charges twice i.e. charges for STOA in addition to charges for LTA taken has also been addressed subsequently. Hon'ble Commission has amended CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 and provided for adjustment of charges paid for MTOA and STOA against the charges for LTA (in the event of MTOA and STOA being in the same region for which LTA has been granted).

4.2.7 However still some of the possible reasons of applicants for not taking LTA and opting for sale of large quantum of power through Open Access could be due to the fact that:

a. There is no commitment to payment of transmission charges if LTA is not taken.
b. Hydro power stations have low load factor of the order of 30-40% only. By selling power through STOA, they can save as much as 60-70% of transmission charges, though the concerned transmission network mainly caters to their requirement only.
c. The generators by connecting to the grid are availing the benefits of reliability support without any charge.

4.2.8 POSOCO had submitted following comments on the draft amendment to the Regulations vide their letter dated 30th June 2011:

"f) Handling generators granted connectivity without LTA/MTOA:

It is submitted that application for 'connectivity' without any type of access is not in line with the spirit of section 10(3) of the EA 2003 which specifies the duties of a generating company to co-ordinate with the CTU or the STU as the case may be for transmission of electricity generated by it. Grant of connectivity only gives the impression that a generator can 'plug and play' at any point in the grid notwithstanding the provisions in the Regulations that such connectivity will not automatically entitle the generator to interchange power with the grid until it obtains any type of access.

Connectivity Regulations state that the RLDCs must facilitate full load testing of a unit if the system conditions permit. This implies that there must be margins in the *transmission system to accommodate such testing. However we have instances of many generators granted connectivity in a certain pocket in Chhattisgarh/ Odisha which could lead to constraints in real time operation. Grant of such connectivity implies that all reliability related issues get shifted from the 'planning' to the 'system operation' phase which has the potential to seriously compromise on the grid security.*

Hence it is suggested that the CERC might mandate that connectivity applications must be accompanied by LTA applications and the time frames need to be honored so that we do not have stranded generation or stranded transmission nor is the grid security unduly compromised."

4.2.9 *Earlier transmission system associated with Central Generating Stations, UMPPs and entities like DVC came through coordinated planning process and the transmission plans were discussed and approved in the Standing Committee on Transmission Planning. Subsequently IPPs came as regional entities and they were required to apply for LTA / connectivity. Thus there are two distinct classes of generators, which have been recognized by the Hon'ble Commission in the 2nd amendment to Sharing of Inter-State Transmission Charges And Losses Regulations, (quoted below)*

"Provided further that where long term access (LTA) has been granted by the CTU, the LTA figure, and where long term access has not been granted by the CTU, the installed capacity of the generating unit excluding the auxiliary consumption, shall be considered for the purpose of computation of approved injection."

4.2.10 *The Hon'ble Commission, in order dated 31.3.2012 in petition nos. 289/2010 and 290/2010 had directed the CTU to ensure that all generators sign connectivity agreement. On similar lines, it is suggested that the Hon'ble Commission may direct all the stakeholders going in for inter-state transactions to avail LTA for full exportable capacity including overload capacity, if any.*

4.2.11 *Many a times, generators apply for connectivity / LTA when the station is in an advanced stage of construction. Pending commissioning of pooling station and transmission system, the CTU is left with no other alternative but to allow LILO of lines passing nearby to provide start-up power. However, it is observed that such arrangement becomes quasi-permanent and continues for years together. Generally LTA becomes effective after commissioning of regular transmission system including pooling station. The generators provided connectivity through LILO arrangement continue to evacuate generation through the LILO lines. Grid security is also compromised as a trunk line (made LILO) becomes vulnerable to tripping due to bus fault at the power station, fault in LILO portion etc. Hence it is* *suggested that LILO of trunk 400 kV and & 765 kV lines should be used only as last resort, and after taking prior approval of the Hon'ble Commission.*

4.2.12 *Further, in the recent past, there have been instances where the generators have sought a reduction in LTA. Two such cases where LTA has been reduced are given below:*

Lanco Kondapalli: 350 MW to 250 MW

Torrent Power: 500 MW to 300 MW

Such a trend is unhealthy and may create issues in regard to the sharing of transmission charges by the generators specially in the case of hydro generation and intermittent generation and this needs to be checked immediately.

4.2.13 *Taking into consideration, all the facts stated above, it is suggested that It should be made mandatory that the new generators seeking Connectivity should also apply for LTA corresponding to the quantum that shall be injected to the grid, including overload capacity. It has to be appreciated that connectivity application is seeking connectivity to utilize the transmission services rendered by the grid. Such services shall be utilized by the applicant with or without firming of beneficiaries i.e. under Long term, medium term or short term access modes. Therefore, unless applicants take LTA for the capacity equal to the power likely to be injected in any of access modes i.e. Long term, medium term or short term access, the adequate capacity margins in the grid may not be available. Connectivity as well as LTA should become effective simultaneously and both should have definite time period, to be renewed at regular intervals subject to prevailing Grid conditions. However, to take care of emergent and seasonal small requirements as well as to harness the spare generation capacity, CPPs embedded within state network with surplus capacity upto 150 MW may be granted exemption, and such entities need not avail LTA.*

4.2.14 *It is also suggested that all transactions by an entity, including Long Term with identified beneficiary, Medium Term Open Access and Short Term Open Access should be limited to the quantum of LTA availed. The term merchant plant basically implies that it is a plant which does not have a PPA. However full quantum of power from the plant has to be evacuated and hence LTA is essential.*

4.2.15 The National Load Despatch Centre (NLDC) has filed a petition No. 225/MP/2012 in September 2012 seeking following amendments to Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-Term Open Access inter-State Transmission and related matters) Regulations, 2009 (hereinafter referred to as the 'Connectivity Regulations':

i. Entities seeking connectivity may be required to avail Long Term Access (LTA) for the quantum of injection or withdrawal, including overload capacity, if any, sufficiently in advance, so that the transmission system required comes into operation well before the commissioning of the generator;
ii. Any type of open access to the ISTS may be provided within the overall limits of LTA availed.
iii. Direct all generators to apply for LTA for the entire output (including overload capability); and

Copy of the petition no. 225/MP/2012 filed by POSOCO is enclosed at **Annexure-V**

4.3 ISSUES RAISED BY GENERATORS

4.3.1 As few generators were granted Long Term Access without beneficiaries or based on target region, these generators even after getting Long Term Access faced many problems like paying long term transmission charges for region in which they did not find beneficiary. Also in many cases no additional network was developed and they were accommodated on existing network margins, after a few years they suddenly started facing problem because of congestion in the system. The congestion in the system arose due to coming up of new generators which required the same network for transfer of power. Generators could not avail Long Term Access because of no firm beneficiaries and with the coming up of new generation capacity there application for access was considered at par with the new generators i.e. under MTOA/STOA, which resulted in congestion.

4.3.2 The operationalization of Long Term Access on commercial basis and technically without any new transmission asset being built is creating a situation wherein the generator sought 'right of use' of network. The right of network use depends on type of access along with type of contract with buyer. As generators were having long term access to ISTS, they started demanding right of use or at least ‘first right of use’ i.e. they sought priority in availing short term open access. In accordance with the Electricity Act, 2003, Open Access is to be operated on the principle of non-discriminatory Open Access. RLDCs in accordance with Section 28(3) of

Electricity Act, 2003 are responsible for scheduling and dispatch of electricity in accordance with contracts entered into with licensee or the generating companies operating in the region.

4.3.3 So in the case of Short term contract (of power) under short term open access, any priority to holder of Long Term Access to ISTS cannot be given, but such type of request overwhelmed the system operator along with litigation.

4.3.4 So this position needs to be clarified. Although a commercial adjustment to these generators was given in form of adjustment of Long term open access charges with short term charge paid (for injection in any region and with-drawal charges in target region), it does not solve the problem of congestion.

4.3.5 Therefore, the rights of Long Term Access are required to be clarified. Although CTU in its submission proposed two type of long term access and submitted that priority may be given in Short term open access to generators having long term access in target region, this issue needs to be addressed so that the payment of long term charges or medium term charges should not be viewed as right on transmission service unless similar contracts are available. In a way, this transmission service agreement became operationalized only with power contract of similar level (timeframe). The past payment for LTA should not be seen as a tool to distort scheduling and despatch process.

4.3.6 In this regard we would like to quote from para 18 of the Staff paper brought out in 2008:

> --------Even if the size and location of a generating station and its beneficiaries are such that the incremental power flows could prima facie be accommodated on the existing system, it has still to be checked by the concerned STU/CTU that normal redundancy margins are not encroached upon in the process. This must be done sufficiently in advance, so that if the studies show any inadequacy in the system, time is available for carrying out the required augmentation. In case, this is not done in good time, the generating company may be required to restrict its generation, and it cannot claim a priority for use of the transmission system under "open access" or any other provision, particularly if the generating company itself has been negligent in the matter. **"**

4.3.7 The encouragement for seeking Long Term Access should therefore be seen as an effort to mitigate possibility of congestion by building sufficient evacuation system and not as a commercial mechanism either for collecting more transmission charges for transmission licensee or withholding right of generators on transmission for any priority on transmission access.

4.4 Issues raised by Users, Open Access Customers and Power Exchanges:

4.4.1 Users like DISCOMs are facing problem of congestion in getting Medium Term and Short Term Open Access. Similarly Open Access Customers in search of efficiency of power procurement want to utilise power market but are finding it difficult to get power on regular and reliable basis due to congestion. The congestion in ISTS is less frequent than congestion in intra -state transmission system where requisite development of state's transmission system network has not taken place due to various reasons. The issue of congestion needs to be handled through better transmission planning and operational management of grid rather than a commercial arrangement of forcing LTA or limiting all transactions to the overall limits of LTA availed by generators/ drawee entities.

4.4.2 Further, Power Exchanges, which are transparent platforms for transactions, are facing problem of Congestion more frequently than bilateral transaction as allocation to Power Exchanges is being done in the end. This reduces the confidence of participants in trading through power exchanges and sometime just for higher probability of transaction being successful, they opt for bilateral transactions. An analysis shows that due to this tendency, economic operation of power sector i.e. merit order operation gets disturbed.

4.5 Issues raised by Users in regards to Transmission Charges:

4.5.1 Few beneficiaries have raised the issue of high transmission charges and their grievances are mainly due to:

(a) 50% Uniform Charges applied for transmission charges.

(b) Slab System in Transmission Sharing Regulations.

(c) Levy of transmission charges on the basis of LTA or deemed LTA.

(d) Truncation of Basic Network in load flow studies at 400 kV level.

(e) Payment of transmission charges for Non-ISTS lines being used for carrying ISGS power.

4.5.2 These issues on sharing of transmission charges were considered and third draft amendment of Sharing Regulations was proposed in February, 2014. Stakeholders views on this draft amendment are under consideration in the Commission.

4.6 UTILIZATION OF HCPTC TRANSMISSION ASSETS

4.6.1. Commission granted two major regulatory approvals:

a. In Petition No. 233/2009 in March,2010 : Nine High Capacity Power Transmission Corridors- (HCPTC)

b. In Petition No. 154/2011 in August,2011: Two High Capacity Power Transmission Corridors and two Connectivity related projects

Power map of India, indicating these High Capacity Corridors is enclosed at Annexure- VI

4.6.2. CTU has raised concern about the fact that some of the generators are either abandoning their project or requesting for surrender of LTA or are rescheduling their projects which is affecting implementation of some of the above mentioned high capacity transmission projects.

4.6.3. To understand the severity of issues raised by the CTU, the extent of deviation needs to be examined. The nine High Capacity Corridors were planned based on BPTA signed by IPPs with CTU. The phasing of implementation of these HCPTCs was done in accordance with commissioning schedule given by these IPPs. While granting regulatory approval to these corridors, the Commission had instructed CTU to match the transmission projects with scheduled commissioning of Generating stations. CTU conducted regular meetings with the generating stations to seek inputs in regard to their commissioning. Some of the transmission system associated with HCPTCs was also being implemented under competitive bidding process.

4.6.4. Status of transmission projects forming part of HCPTC as on 1.4.2014 is given at **Annexure VII** and status of IPPs for whom the transmission system is being developed is given at **Annexure-VIII**. From the progress of these projects, it is evident that there is slippage in the commissioning schedule of many generating stations. The slippages may be due to reasons linked to fuel issues, execution delays, etc.

4.6.5. However, in view of fact that not many IPPs are opting out, degree of utilisation of transmission corridors may improve with passage of time.

4.6.6. Also one issue which has recently emerged is that a few of these IPPs which earlier indicated their target region as NR/WR are now seeking power transfer to SR.

4.6.7. Following three issues therefore need to be addressed:

a. Deviation from Commissioning Schedule
b. Shifting of Target Region.
c. Exit from LTA

4.6.8. In this regard it is important that issue of Exit in the era of Open Access is not a simple matter which can be decided only on the basis of "stranded capacity" but issue of affecting other parties market access and its effect on competition is also a matter of concern. Any exit needs to be considered in accordance with various parameters like time of request for exit or shifting of target region, stage of investment of the transmission system, impact of exit or shift on existing ISTS customers and future scenario of usage of the asset .

4.6.9. A balanced view needs to be taken in regard to liability of generators, avoidance of building underutilized assets and protecting consumer interest for the period during which asset is underutilized. For this there is need to formulate commitment mechanism for both generator and drawee entity.

4.7. Issue of Congestion Management

4.7.1. In the year 2010 Commission took Suo-motu action on the issue of Congestion in Petition no. 67/2010; the salient points from Commission’s order dated 10.3.2010 in petition no. 67/2010 are given below:

"1. The Commission took note of the fact that all transactions carried out through the Power Exchanges could not fructify on account of frequent congestion experienced in the transmission of power and directed National Load Dispatch Centre, Centre Transmission Utility, all Regional Load Dispatch Centres and Central Electricity Authority to make presentations before the Commission on the causes of congestion. The percentage of time that congestion was faced by the

Indian Energy exchange (IEX) and Power Exchange of India Limited (PXIL) in the Northern Region during the month of December 2009 to January 2010 were as under:

Exchange	*December 2009*	*January 2010*
IEX	*43%*	*47%*
PXIL	*19%*	*13%*

14. The Commission had further observed that the frequent congestion apart from hampering the development of the power market had also resulted in increased incidents of grid indiscipline. When the utilities were unable to arrange power through the Power Exchanges on day-ahead basis, they sometimes resorted to overdrwal of power through Unscheduled Interchange (UI) in real time. This resulted in further congestion of transmission corridors. It was also observed that power flow on inter Regional Links in real-time was sometimes more than the Total Transfer Capability (TTC) declared by Regional Load Dispatch Centers. The violations of TTC and consequently the "reliability margins" endangers the security and stability of the grid.

19. We have considered the submissions made by the NLDC, CTU, UPPCL, APTRANSCO, TATRANSCO and PTC. We direct the CTU to carry out the execution and commissioning of various elements in a time bound manner as indicated in the Annexure-I to the order and also expedite the same wherever possible. We also direct the CTU to take immediate steps to remove the constraints highlighted by TANTRANSCO for evacuation of power in the Vemagiri area caused due to LILO arrangements of the existing transmission lines. In case, there is a change in the scenario in which the connectivity/ long-term access were given by the CTU, adequate corrective measures need to be taken by the CTU immediately.

20. It is observed that the transmission system of the State Transmission Utilities and the CTU or the other transmission licensees all being inter connected, we underline the need for a coordinated approach by the CTU, STUs and other Transmission Licensees for implementation of the various transmission system schemes so that unhindered flow of electricity may be ensured from the surplus to the deficit parts of the country and there is no generation bottled-up in the country. We direct all the agencies concerned to implement the various schemes in a time-bound manner so that the Open Access envisaged in the Act is implemented in letter and spirit. The Power Exchanges offer a neutral and transparent platform and with the implementation of these schemes, more volumes of electricity trades would be cleared resulting in better utilisation of the scarce generating facilities in the country in meeting the power aspirations of the consumers.21.The National Load Dispatch Centre is directed to regularly monitor the congestion points and submit a quarterly report to the Commission and CTU in the first week of January, April, July and October of each year.

The CTU is also directed to make all efforts in coordinated planning and to take remedial measures to relieve congestion wherever foreseen. "

4.8. Status of congestion

4.8.1. POSOCO has been regularly providing operational feedback [4]in regard to congestion being experienced in Indian Power Grid. The latest report is available at:

http://posoco.in/documents/operational-feedback

4.8.2. In addition to the regular operational feedback, POSOCO has also submitted a document on Prioritisation of transmission corridors [5]indicating mismatch between generator commissioning and transmission system which is resulting in congestion.

4.8.3. CTU was instructed to take action to mitigate congestion. It is understood that CTU and CEA are taking into consideration this operational feedback in the planning of Inter-State Transmission System. However specific actions taken in this regard are not clear as the Draft National Electricity Plan (Draft) prepared by CEA in February, 2012 does not specifically identify schemes for mitigating congestion. Over emphasis on generation evacuation plan may be one of the reasons for congestion. In some cases the congestion may be due to slippage of major generation projects and in such cases congestion may diminish not before long.

4.8.4. As per power market report of CERC, the volume of electricity that could not be cleared due to congestion during 2012-13 is 4647MU in power exchanges alone and the amount collected through Congestion revenue was Rs. 453.3 cr.The volume of electricity that could not be cleared due to congestion during 2013-14 is 5591 MU(report under publication) and amount collected through Congestion revenue was Rs 392.33 Cr

Table 3: Details of Congestion in Power Exchanges 2013-14

4 http://posoco.in/documents/operational-feedback

5http://nldc.in/attachments/article/87/Prioritization%20of%20Transmission%20Elements_Feb%202014.pdf

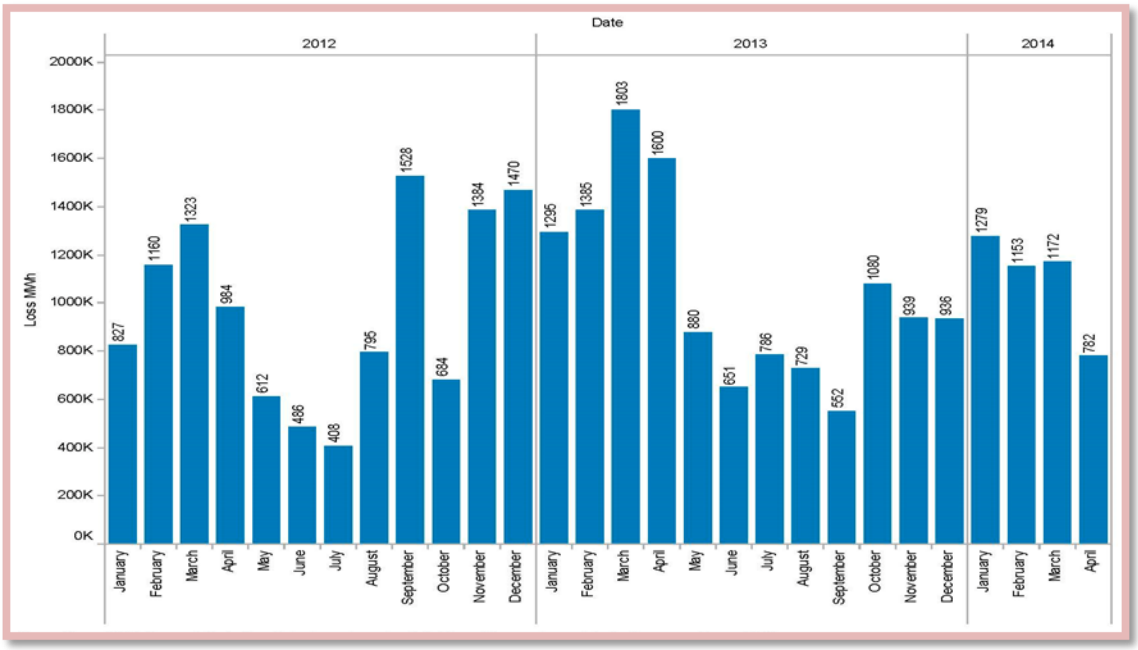
Details of Congestion in Power Exchanges, 2013-14			
	Details of Congestion	IEX	PXIL
A	Unconstrained Cleared Volume* (MU)	34230.41	1390.62
B	Actual Cleared Volume and hence scheduled (MU)	28923.23	1106.39
C	Volume of electricity that could not be cleared and hence not scheduled because of congestion (MU) (A-B)	5307.18	284.24
D	Volume of electricity that could not be cleared as % to Unconstrained Cleared Volume	15.50%	20.44%
* This power would have been scheduled had there been no congestion.			

Source: IEX, PXIL & NLDC

4.8.5. The e-bidding for transmission corridors also gives indication of congestion. The detail of e-bidding are given in **Annexure-IX**. The amount collected through e-bidding is Rs.558.38 Cr. This indicates that transmission congestion is affecting not only the cost of power to the ultimate consumer but is also affecting the availability of power. Few generating stations needed to back down their generation and sometime they may operate at in-efficient operational levels.

4.8.6. IEX data: The congestion which was earlier limited to S1-S2 area is now appearing in other parts of the transmission system as well. The market splitting has also been increasing from 2 areas earlier to now 5 areas. The power exchange transaction over inter regional links are decreasing. The energy which could not be transferred due to congestion in transmission system during the period from January, 2012 to April, 2014 is as shown below:

Figure 4: Energy not transferred in IEX due to Congestion.



4.8.7. In petition no. 188/SM/2012 and 240/MP/2012 generators raised the issue of congestion.

4.8.8. Also there is a need to formulate quick solutions with expeditious implementation of transmission link to resolve the problem of congestion. If necessary these **schemes can be considered for higher returns,** if after completion in constrained time period they can provide mitigation of congestion.

4.8.9. In inter-regional power transfer, non availability of adequate transmission links and redundancy may cause incidences of high impact like grid disturbance.

4.8.10. The congestion at least on the injection side may be outcome of short-sightedness on the part of Generators either in declaring the quantum of LTA or scheduling of their requirement of LTA in a conservative manner i.e. to avoid seeking LTA till last moment waiting for PPA to be finalised.

4.8.11. The congestion in a growing power market cannot be completely eliminated, but if it obtrudes the achievement of true objective of a competitive power market by depriving customers in some part of the country due to inadequacies in transmission planning by utilities, it needs to be tackled.

4.8.12. The solution suggested in this concept paper is based on the basic principle that the transmission cost is only a fraction(less than 10%) of energy cost and any conservative approach in transmission planning results in congestion and it only increases the cost of power manifold (Congestion price of Rs. 6 to 15 as compared to energy cost of Rs 2 to 5 per unit). Further it may also lead to incidences like grid disturbance. The inter-regional transmission system needs to be planned taking all possible skewed load generation balance, it cannot be merely planned for transferring seasonal and daily surpluses.

4.8.13. On generation side it is proposed to include all type of transactions in transmission planning and on drawal side it is the responsibility of state power utilities that they participate in proposed transmission planning in a more pro-active manner. Hence by shifting from LTA based transmission system to installed capacity including over-load capacity based transmission planning, consumers may be saved from congestion.

4.8.14. On system operation side, better visibility through Phasor Measurement Units and a transparent and more inclusive process of declaration of Available Transfer Capability through Reliability Council would result in optimum utilization of existing transmission corridors. There is need to consider dynamic ratings of the transmission lines for declaring transfer capability.

4.8.15. There is an urgent need for formulating equity or debt funding of congestion relieving transmission systems through congestion revenue.

4.9. Environmental Issues in Transmission

4.9.1. Time has come when development process is integrated with environment in a true manner to make it conducive for sustainable development. In one of the cases, a court has made an observation in regard to environment impact of transmission projects where all options were not explored completely which may have resulted in minimization of impact on environment.

4.9.2. While transmission infrastructure is necessary for economic development, if these decisions are taken in a transparent manner and all environment impacts are properly brought out, optimum transmission planning can be done. Conservation of Right of Way being an important objective, comprehensive transmission system can be evolved keeping in view the future need of network instead of piecemeal transmission projects for generator. Consumer engagement is necessary from initial stage, to avoid hindrance and litigations at later stage. The support of state government is necessary in explaining the importance of transmission lines to local population to avail power supply from cheapest source for mitigate power shortage.

5. TRANSMISSION RELATED ISSUES AND SOLUTION SUGGESTED BY CTU/CEA AND POSOCO

The issues being faced by (a) CTU/CEA in transmission planning and POSOCO in system operation can be categorized as under:

5.1 PLANNING ISSUES

Following planning related issues are being raised by CTU

5.1.1. How to plan the transmission system in a scenario where generators are seeking Connectivity for Installed Capacity and LTA for less capacity ?,

5.1.2. How to plan the transmission system i.e. in which direction as most of generators are seeking LTA without beneficiary(s).

5.1.3. How to plan the transmission system for the drawee entities as they are not giving their drawal requirement form ISTS? [State entities are drawing much more than their entitlement i.e. deemed LTAs due to their allocation in central sector generating stations].

5.2 ISSUE#1: LTA LESS THAN CONNECTIVITY:

5.2.1. **Detail of Connectivity Vs LTA as compared to Installed Capacity**: Based on data collected recently from CTU following picture emerges in regard to Connectivity and LTA**:**

Connectivity Applications

Year	No. of Applications	Installed Capacity (MW)	Connectivity Applied (MW)
2010	90	1,03,376	96,220
2011	52	60,242	57,927
2012	29	15,209	14,154
2013	9	13,342	11,571
Grand Total	180	1,92,168	1,79,872

Table 4: Connectivity Application

LTOA/LTA Applications

Year	No. of Applications	Installed Capacity	LTOA/LTA Applied
		(MW)	(MW)
2009	15	8,719	6,484
2010	34	27,959	21,738
2011	39	44,126	32,993
2012	21	11,010	6,672
2013	5	2,480	2,342
Grand Total	114	94,293	70,228

Table 5: Detail of LTA Applications

5.2.2. It is true that in comparison to the connectivity applications, the applications for LTA are less. This position is due to time differential between applications for connectivity and LTA and the present system of charging of transmission system based on LTA. While generators need connectivity immediately for financial closure, the requirement of LTA is required to be indicated about 3-4 years prior to the intended date of availing LTA. Thus, there may always be some difference in quantum of connectivity and LTA.

5.2.3. Present position can be summarized as:

a) While Generator sought connectivity, they sought LTA only for a part capacity.

b) If Generators succeed in plant commissioning, they were not able to identify and finalize their beneficiaries till last minute.

c) Due to above two reasons, plants in the Central part of country (W-3 area) sometime faced congestion after their plants were ready. This created problem in system operation in the country.

d) Also some of them wanted to change their target region from NR and WR to SR , which was not feasible at the last moment.

e) Some of the generators were not able to complete their projects due to lack of statutory clearances or in adequate availability of fuel. , However they kept informing the transmission planner that the clearances/fuel would be obtained and kept on shifting their scheduled commissioning date.

f) Transmission planning and execution agencies under cost plus and competitive bid projects keep on implementing the projects as per original schedule to avoid bottling up of power.

5.2.4. As Connectivity is not linked with the liability to pay the transmission charges, generators are applying for Connectivity as it helps them in getting finance. Also in case of any change in plan like rescheduling, under scaling or abandoning the project, there is no impact on generators.

5.2.5. Sufficient safeguards are required to be built in so that CTU gives Connectivity after assessing the progress of generating project. However in accordance with CERC Connectivity Regulation 8(8) as the connectivity line is to be planned and executed as ISTS, there is need to safeguard investment in transmission system in view of the fact that sufficient safeguard is presently not available in the event of developer of generation project quitting the project.

5.2.6. One option is amendment of Regulation 8(8) so that generators themselves build the Connectivity line and second option that if CTU builds it then Connectivity should not be free .In the context of second proposal of CEA in regard to General Network Access (GNA) appears appropriate and is discussed later.

5.2.7. The problem on account of LTA being less then installed capacity is not as acute because most of the generators are seeking LTA corresponding to 70-80% of their installed capacity. The reasons for this conservative approach are nevertheless important to understand. These are:

i. Fewer Case- 1 biddings.
ii. Payment of transmission charges based on LTA, thereby avoiding payment for full capacity of generating station.
iii. Awareness of the margins available in transmission system due to planning based on peak scenario,
iv. Lack of flexibility in regard to adjustment of STOA charges
v. Lack of flexibility in change of region under LTA

vi. State Utilities of home State sometimes insist at the last moment to build separate line for power transfer to avoid payment of PoC charges

5.2.8. It is true that some of the new generating capacity in the private sector is not tied up due to issues related to competitive bidding and fuel related issues but this makes transmission planning difficult. However, in case generators seek General Network Access (GNA) commensurate with their Installed Capacity, as is being mooted now, CTU and CEA can plan their system based on anticipated load generation scenarios.

5.2.9. The probabilistic transmission planning based on anticipated load generation balance require scenario analysis and to compare various options of transmission investment, active participation from State utilities is required in transmission planning process.

5.3 ISSUE # 2: LTA WITHOUT BENEFICIARY

5.3.1. As most of the generators at the initial stage of project development did not know who will be their beneficiary as it would be known only after they succeed in case 1 bidding. They seek LTA without beneficiary based on target region. This target region they indicate based on anticipated demand supply position in the country or discussion with CTU. The system is built on this basis, then there may be some mismatch at later stage because forecasted demand supply situation may change or they can win competitive bidding in other region. CTU response is that Transmission System cannot be built on 360^{O} basis. This situation may possibly result in some under utilization for some period till new generation/ demand does not come up.

5.3.2. The role of CEA and CTU in coordinated Transmission Planning as well as forecasting demand supply situation become more important in this type of situation as they have more information available about the emerging situation based on which probabilistic Transmission Planning along with phased implementation and mid-course correction can be built in. The role of State Utilities is also very significant because unless they give the requirement of transmission system it would not be possible to do scenario based transmission planning.

5.4 Issue#3: Projection of drawal Requirement from ISTS

5.4.1. At present States are not giving their drawl requirement from ISTS and drawing power from ISTS more than their entitlement . From the data of Drawal of electricity by State utilities from ISTS as compared to LTA , it is clear that majority of states are drawing power more than their LTA . Drawal from ISTS as compared to LTA in 2012-13 is attached as **Annexure-X.** However, this data provides very good input and is validating the anticipated drawal in NR and WR, which was anticipated while granting LTA based on target region . At present transmission cost allocation system which is modulated through uniform charges and slabs is going to the benefit of such States only. Therefore, there is a need to review implementation of present mechanism of sharing of transmission charges.

5.4.2. Draft recommendation of the Advisory Sub-group on transmission constituted by Ministry of Power also mentions this, as could be seen from the extracts given below:

"However a way out has to be found assuming that long term PPA may not materialize to a large extent. The existing transmission service products need to be reviewed as well as approach to planning so as to provide flexibility to buyers and sellers. New transmission systems would have to be developed to cater to the need of short/medium term market including power exchange (PX). However, any fresh investment should be supported by commitment to pay for it otherwise the burden will be passed on to others. States like Punjab, Tamil Nadu, Gujarat, UP etc. **availing more import capacity through ISTS than their LTA capacity should bear the PoC charges at the point of drawal accordingly**. In the present regime states active in Electricity market have got additional system strengthening done to draw power much more than their LTA without any liability to pay. As a result there is hidden cross subsidy and eastern States who seldom import more than their LTA have to pay more."

5.4.3. Therefore, the generators cannot be blamed for the present situation. The solution lies in correcting the transmission planning and transmission cost allocation process.

5.4.4. However before asking the states to give their requirement of transmission system in advance and pay accordingly as proposed in GNA system, following issues need to be understood:

a. Behavioral issues: If someone is asked to declare his requirement and take responsibility for payment, it is natural to under-declare. While this may satisfy commercial equation, but if it is taken as input for planning as it is, it will result in development of transmission system of less capacity, which will in turn lead to congestion.

b. Structural issue: With unbundling of vertically integrated structure of power utilities in States, STU’s are also facing similar problem as they do not have complete picture. They may get inputs from their Discoms about their anticipated power requirement and power procurement plan, but the behaviour of open access customers is not certain. Similarly, a new generating station in the state, selling power outside would entirely change power flow pattern and State's drawal from ISTS would substantially change. Thus, works of Central Transmission Utility is not as simple as plan and build transmission system based on projected load generation balance; it needs to play a leading role of guiding State Transmission Utilities for optimum and integrated transmission planning for smooth flow of electricity from the generating stations to load centres.

5.4.5. If a suitable mechanism of payment for state lines being used for carrying Inter-State power and ISTS lines used by state embedded generators can be developed, transmission planning process can be made more broad based avoiding duplication of transmission assets.

5.4.6. Using inputs from sharing of transmission charges: The quarterly computation in PoC mechanism provided a validation point for planning process for both CTU and STU. The trend analysis will capture need for course correction and validation of load generation balance considered in planning.

5.4.7. New roles expected from the planning agencies: The transmission utilities need to be aware about power market condition like availability of cheaper source of power, elasticity of demand of different consumers, etc, and based on system configuration, and usage pattern CEA/ CTU may suggest transmission as a replacement of new generating capacity. It requires integrated system planning study based on anticipated price of electricity generation in various areas/zones in addition to conventional inputs like fuels and plant locations.

5.5 Solution suggested by CTU:

5.5.1 In view of their experience in regard to connectivity, LTA and MTOA Regulations, CTU took up the issues with Ministry of Power vide their letter dated 30.08.2011.

5.5.2 In its letter of 30.01.2011 to Secretary, CERC, CTU suggested as under:

1. *For the new IPP generation including captive power station eligible for getting connectivity with ISTS, it should be made mandatory to apply through combined application for Connectivity and LTA. However, renewable and solar generation projects may be exempted from this stipulation.*

2. *There should be provision of assigning responsibility of development of Connectivity line by IPP developers if they are required in the time period less than the 9 months CERC time lines.*

3. *The LTA may be categorized in two categories*

   a. *Category – A : LTA with firm beneficiary(ies)*
   b. *Category – B : LTA with target beneficiary/region*

4. *Provision for Financial Adjustment of LTA Transmission Charges paid by different Categories of LTA vis-à-vis MTOA/STOA Charges as explained above may be made.*

5. *Pre-requisites in the form of achieving milestones before taking up Implementation of Transmission System for grant of LTA/Connectivity may be defined. Further, provision may be made for encashing of Bank Guarantee (BG) of the projects which have signed BPTA/TSA and have failed to achieve defined milestones may be made.*

5.5.3 Also in the Communications of 30.08.2012 and 19.09.2012 to Ministry of Power, CTU suggested following way forward:

1. *It should be made mandatory that the new generators seeking Connectivity should also apply for LTA corresponding to the quantum that shall be injected to the grid after discounting for auxiliary consumption. Here it may be mentioned that the Connectivity application shall be disposed quickly and LTA application after due deliberations with the stakeholders. It has to be appreciated that connectivity application is seeking connectivity to utilize the transmission services rendered by the grid. Such services shall be utilized by the applicant with or without firming of beneficiaries i.e. under Long term l medium term or short term access modes. Therefore, unless applicants take LTA for the capacity equal to the power likely to be injected in any of access modes i.e. Long term, medium term or short term access, the adequate capacity margins in the grid would not be available to give them service.*

2. *Concerted efforts are required to tie-up long term beneficiaries. In the last few years considerable Inter-State Transmission Systems have been planned based on the target beneficiaries indicated by the generators. As per the regulations these generators were required to identify the point of Drawal (State periphery) at feast 3 years prior to COD which most of generators have not complied. This is serious matter of concern in the context of transmission congestion particularly at the Drawal end as well as grid security.*

One copy each of aforementioned letter from CTU to Ministry of Power are enclosed at **Annexure- XI**

5.6 Solution suggested by System Operator

5.6.1 NLDC, has suggested following:

i. Entities seeking Connectivity may be required to avail Long Term Access (LTA) for the **quantum of injection or withdrawal**, i**ncluding overload capacity**, if any, sufficiently in advance, so that the transmission system required comes into operation well before the commissioning of the generator;

ii. Any type of open access to the ISTS may be provided within the **overall limits of LTA availed**.

iii. Direct all **generators to apply for LTA for the entire output (including overload capability);**

5.6.2 The solution suggested by CEA and CTU is based on concept of GNA wherein system planning is proposed to be based on GNA i.e. injection and Drawal requirement and transmission charges shall also to be paid on the basis of GNA.

5.7 Solution proposed by CEA

5.7.1 Initially both CEA and CTU were of the opinion that 360 degree planning is not possible and accordingly the revised planning criteria issued by CEA in January, 2013 specified that that source sink relationship should be known five years in advance to plan a transmission system.

5.7.2 The problem being faced in transmission planning and issues raised by CTU, CEA and system operator were discussed in the Central Advisory Committee meeting held on 20.3.2013 in the backdrop of CEA transmission planning criteria, published in January, 2013, specifying that at least 85% of the generating capacity should by tied up under long term for the purpose of transmission planning. After detailed discussion, there was consensus in regard to the following:

- The Regulation cannot be in conflict with Act and Policy.
- PPA should not be a pre-condition for connectivity and long-term access. But at the same long-term PPA should be encouraged through the requirement of DISCOM's power procurement adequacy statement by SERC.
- Redundancies should be created in the transmission system.
- State transmission planning needs to be improved.
- There is a need for levy of charges for connectivity. It should not be free. There should be financial incentive/disincentive for Connectivity and LTA.
- The Commission should introduce Capacity Market with double-sided bidding.

A copy of minutes of meeting of Central Advisory Committee meeting held on 20.3.2013 is given at **Annexure-XII**

5.7.3 During later part of 2013 and early 2014 a new General Network Access (GNA) based solution has been mooted, which takes into account ground realities of Indian power sector and is in variance with their earlier proposition.

5.7.4 The Sub group on transmission / CEA suggested concept of General Network Access (GNA), which is described below in section 6.8.:

5.8 General Network Access (GNA)

5.8.1 The Generators and the States/Consumers could be given General Network Access (GNA) to ISTS for the **agreed quantum of power (MW) with commitment to pay for the transmission charges**. While granting GNA the generation and load scenarios and other assumptions would be declared by the CTU. A GNA agreement could become the driver for investment. Salient points of GNA based system in respect of Connectivity and Access to ISTS are as under:

i. Under the GNA system the payment of transmission charges is also proposed to be **linked with GNA**.

ii. GNA shall be the permission granted by the CTU to the buyer/seller to draw or inject specified quantum of power in MW from a given point of connection (PoC) to/from any ISTS point as assessed by the CTU through system studies**. No injection/ withdrawal beyond GNA will be allowed.**

iii. The GNA holders shall not be required to pay any additional transmission charges up to its GNA capacity. However, for any **capacity injected or drawn over GNA capacity shall attract enhanced POC charges on the excess quantum.**

iv. The GNA customers shall have higher priority over the customers other than GNA customers in scheduling. The customers other than GNA customer shall be scheduled on margins available in the transmission system.

v. For access sought by the drawing entity (DISCOM, OA consumers) above its GNA, request shall be entertained only for STOA/PX service after accommodating GNA holders and at a premium (say 25% or 50%).

vi. The inter-se-priority amongst LTA, MTOA, STOA and PX will lose its relevance under GNA regime for the purpose of scheduling. Because it is expected that the capacity should always be scheduled and despatched under GNA regime irrespective of type of Open access or access and sufficient transmission capacity should be available all the time to cater for all the GNA customers. However, in certain pockets or lines there may be possibility due to forced outages at times and then the priority for scheduling should be in the order of LTA, MTA, STOA/PX and the curtailment in the reverse order of priority. All existing LTAs (point to point) or (Target Region) shall be automatically converted in to GNA.

vii. For grant of GNA, Generator will not have to specify drawal points and Drawee entity will not have to specify injection points. Entities seeking GNA shall have to sign Transmission Service Agreement (TSA), furnish BG etc. for enabling implementation of the transmission system.

5.8.2 **Benefit of GNA as per CEA**

a. New transmission corridors could be planned based on GNA requirement, which would help in a great way to remove congestion in transmission corridors.
b. Generators shall not be liable to pay notional point of drawal charges
c. Generators shall not have to declare target beneficiaries
d. Generators shall have access to ISTS grid with flexibility for point of drawal subject to conditions laid down at the time of grant of GNA.
e. Drawing Utilities shall also access to ISTS to the extent of their GNA and get the system created for power transfer over ISTS from anywhere in the grid.

5.8.3 The details of GNA concept and its implementation (as per email from CEA) are given at **Annexure-XIII**

5.8.4 **Observations on GNA Proposal :**

CEA consulted various state utilities on GNA during 23.12.2013 to 4.1.2014 . While Views of all stakeholders are not available on GNA , a copy of views expressed by some of the stakeholders is enclosed as **Annexure-XIV** The reaction of stakeholders is mixed.

5.9 VIEWS OF STAFF OF THE COMMISSION

5.9.1 GNA concept put forward by CEA has distinct merits so far as the transmission planning and congestion mitigation is concerned. However few suggestions do not seem to be in line with non-discriminatory open access principle prescribed in Electricity Act, 2003 and transmission cost allocation principles given in National

Electricity Policy and Tariff Policy. Also there are few issues which are not addressed by GNA.A modified approach is therefore proposed in the staff paper.

5.9.2 It has been proposed that the new transmission corridors could be planned based on GNA requirement, which would help in a great way to remove congestion in transmission corridors.

5.9.3 The proposition appears to be in order as GNA will be based on installed capacity and existing practice of LTA for part capacity will not be allowed. This will help in mitigating congestion in future.

5.9.4 It has been proposed that the Generators shall not be liable to pay notional point of drawal charges.

5.9.5 The State Utilities are not in agreement with the same. Such a proposition may lead to either of the following:

a. The asset remains underutilized with respect to intended use
b. liability to pay falls on other users in case generator is not able to find beneficiary

5.9.6 It is not clear as to what will be done in case injection (Generation) GNA is more than Demand GNA Whether the transmission system will be developed as per injection GNA or it will be downsized to match with demand GNA. If it is developed for injection GNA and the demand is not commensurate to the same, the Generator should pay for both the side. In accordance with Electricity Act, 2003 open access requested by Generator needs to be granted and no restriction needs to be imposed because it has no identified beneficiary.

5.9.7 It has been proposed that the Generators shall not have to declare target beneficiaries

5.9.8 The proposition is not clear in so far as implementation is concerned. CEA and CTU were earlier stressing that it is not possible to plan for 360 degree dispersal of power. How the planning will be done under proposed system? Whether CEA and CTU are ready to do perspective planning taking anticipated requirement of power? They along with POSOCO had underlined many times that projections or assumptions which were made at the planning stage did not materialise in the operational time frame. Power transfer between ER-NR and SR-WR anticipated at the planning stage did not come true subsequently. While power transfer between ER and NR did not materialise, power flow between SR and WR happened in the reverse direction. Participation of drawee entities in transmission planning is critical and proper transmission planning cannot be ensured just by commercial mechanism. The State Utilities are also not willing to commit GNA 4 to 5 years in advance and the status cannot be forced for this. This may result in affirmation by Drawee entities that they would only pay for the transmission system when flows on transmission system are same as considered under planning stage. The past experience and development in power sector clearly indicates that it is not feasible to achieve this.

5.9.9 It has been proposed that the Generators shall have access to ISTS grid with flexibility for point of drawal subject to conditions laid down at the time of grant of GNA.

5.9.10 This issue is already posing critical problem and the generators, after getting the transmission system developed for power transfer to WR and NR, are seeking access to SR which may lead to stranded assets.

5.9.11 In real option economic theory each flexibility has a price and whether generators are ready to pay that price for the flexibility or the cost of flexibility falls on other consumers. This issue needs to be addressed.

5.9.12 Problem cannot be addressed till the transmission system is being planned on requisition of the generator and attributed to particular generator this can be achieved. Through perspective planning where advance transmission planning is done on resource and demand projection basis..

5.9.13 It has been proposed that the drawing Utilities shall also have access to ISTS to the extent of their GNA and get the transmission system created for power transfer over ISTS from anywhere in the grid.

5.9.14 The concept of limiting the access to the ISTS based on GNA does not appear to be in order from the consideration of optimum utilization of ISTS. The projected GNA may differ from actual drawal requirement due to better economic growth or even in case of outage of state's own generating unit(s) , drawing entity may want to draw more than its GNA. The same needs to be permitted if margin is available in the tie-lines between the ISTS and the drawee entity.

5.9.15 **Major difference:**

5.9.15.1 It is not clear under GNA concept whether billing of PoC Charge shall be done on fixed quantum of GNA or it will be based on actual usage. With the adoption of GNA concept, the transmission rates (POC Charges) **may have to be calculated considering capacity under GNA including existing LTA**. However user pattern in actual system operation may be different from GNA.

5.9.15.2 The pricing mechanism for payment of transmission charges is proposed to be based on GNA . The transmission pricing based on contract or allocation is an old concept which is to be replaced with actual usage in accordance with the guidelines specified in the National Electricity Policy and Tariff Policy. Relevant extracts from the Tariff Policy are reproduced hereunder:

"*7.1.3 Transmission charges, under this framework, can be determined on MW per circuit kilometre basis, zonal postage stamp basis, or some other pragmatic variant, the ultimate objective being to get the transmission system users to share the total transmission cost in* ***proportion to their respective utilization of the transmission system****. The overall tariff framework should be such as not to inhibit planned development/augmentation of the transmission system, but should discourage non-optimal transmission investment*"

5.9.15.3 The principle of allocation of transmission charge based on usage was adopted in CERC Regulation for Sharing of transmission charges and losses, 2010. The usage based concept is adopted in other advanced countries as well. During last few years, it was found that contract based transmission pricing in the country results in under-declaration of transmission requirement which in turn results in a situation that transmission system which is developed is less than actual requirement and generators have to face congestion in real–time operation. From the data given by CEA and POSOCO, it is observed that the usage of the transmission system by the drawee entities is 50-100% more than their LTA. This is a crucial learning from the past experience which needs to be considered in formulating transmission pricing.

5.10 ISSUS WHICH REMAIN UNADDRESSED IN GNA

5.10.1 **Relinquishment charges**: CTU has over the last one year been expressing concern about stranded assets as many generators for whom the transmission system has already been developed or it is under execution, are either downsizing, rescheduling or simply quitting and seeking relinquishment of their LTA. . Although existing Regulations provide for payment of 12 years transmission charges for stranded capacity, CTU is taking a stand that it is difficult for them to determine stranded capacity in a meshed network, it is not clear how the concept of GNA would take care of this.

5.10.2 **Planning input from Drawee entities**: The mismatch in transmission planning is due to the fact that generators want transmission system to be developed without identifying customers and customers which will ultimately draw power from ISTS are not coming with their future requirement. GNA is trying to force a commitment from drawee entity based on a fixed figure to be given four years in advance. With unbundling and open access it may practically be very difficult for state agencies to firm up their transmission requirement. This issue remains unanswered in GNA and it is presumed that as liability is pre-decided and power drawal more than GNA would not be allowed; it expects that correct input would come from state utilities. This may not come true and it may only increase the tendency to under-declare transmission requirement. Infrastructure planning in this manner may not prove to be successful. The integrated resource planning with collaborative efforts in forecasting demand and supply scenario in which cost of power is going to play a major role in deciding to opt for importing power from outside against costly generation inside the generation will ultimately decide real time system operation. The system should therefore be flexible to accommodate all type of access. Experience shows drawee entities are ready to bear for slightly higher transmission charges to avail the benefit of flexibility.

5.10.3 **Connectivity as a separate product**: The GNA does not propose connectivity as a separate product. The existing provision of Connectivity is an important product for generator for its financial closure and for this either investment is to be made by generator or if CTU is to invest, there are certain lock-ins like availability of land or issue of EPC contract (which is 10% of project value) which provide sufficient safety. The connectivity provides an entry point to the generator as well as and grid are benefited through improved reliability.

5.10.4 Also Regulation prohibits any injection in absence of any type of access even if connectivity is granted. So generator is taking the risk of bottling up his power if he did not seek full LTA. The process of payment based on LTA further discourages him declaring his actual requirement because till he find the customer payment of transmission charge is his responsibility. Such type of generator can inject only under STOA and STOA is given based on available margins. This type of product is available in US power market also. However as discussed in the Central advisory committee meeting, this connectivity may be given with a charge like upfront payment of capital cost of connectivity line or an exclusive liability to pay for the tariff of connectivity line. .

5.10.5 The GNA based planning is capital intensive where for each generator request equivalent transmission investment need to be made, optimum planning take advantage of seasonal and diurnal diversity of demand and some margins available in transmission system are utilised for short term transactions. It should be kept in mind that with CTU in its dual role of planner and executer of transmission projects should not overbuild the system , so there is need of check and balance in transmission planning process where all stakeholders participates and it is done, not only on a fix figure of GNA but it is to be done on options and scenario based analysis where all alternative including non-transmission based solutions like Demand side management , Special Protection Schemes etc also need to be taken into consideration.

5.10.6 It is important to note that the both existing system and GNA system are not very conducive for development of transmission system for Renewable Generation which is a public policy investment. Due to their location away from load centre , low utilization factor and lack of identified beneficiary in the regime of different RPO and REC mechanism, if either of the system is applied as it is then it will hamper growth of Renewables.

5.10.7 So there is need for wider discussions involving all stakeholders since a robust transmission network will help in creating true competition in Indian Power system. It will facilitate fulfillment of objective of open access which gives choice to procure power from any part of the country at lowest price and reduces possibility of abuse of market power by local generators.

6. Regulatory Mechanism for providing Long Term Solution

After detailed analysis of the issues raised by CEA, CTU and POSOCO it proposed to formulate a mechanism for development of a robust and flexible Inter State Transmission system. For this it is necessary that Transmission Planning, Grant of Connectivity and Open Access, and Transmission Cost Allocation mechanism are synergized. For this staff of the Commission held discussions with these statutory organizations and analyzed international practices to formulate various alternatives which can be deliberated for to preparation of regulatory framework for development of transmission system .

6.1 Problem Definition

6.1.1 CTU, CEA and System Operator are underlining that that there being no payment liability for connectivity and sharing of transmission charges also being based on LTA, generators are not seeking LTA upto requisite quantum. This is creating problem in system planning and in future it may result in problems in system operation as well. They are basically suggesting that Connectivity and LTA should not be separate products and the generators should apply for Connectivity for quantum equivalent to LTA (now being termed as GNA) and transmission charges should be payable for the GNA.

6.1.2 While it is agreed that Connectivity and LTA should be at least for the installed capacity of the Generator as a pre-requisite for system planning . However, at present Generators are generally applying for LTA quantum which less than Connectivity and drawee entities are not spelling out their drawal requirement from ISTS in advance, Consequently the transmission planning agencies are not able to plan the system and it has resulted in problems for system operation since both Generator and drawee entities lean on Short Term Access.

6.2 Genesis of problem

6.2.1 After detailed analysis of views of various stakeholders, it is observed that the problem is due to LTA based planning where generators give their LTA requirement less than connectivity and drawee entities do not give their drawl requirement in advance. These issues which are to be handled at planning stage are at a later stage affecting system operation and also have linkage with transmission cost allocation mechanism. The issue is that, if transmission planning is done conservatively based on LTA sought by generators, there is possibility of developing an inadequate system.

6.3 Solution Framework

6.3.1 In view of conservative approach at the transmission planning stage affecting not only the power transmission system but also power market and system operation in long-term, synergised actions need to be taken in regard to various levels of transmission namely planning, execution, transmission corridor allocation and transmission cost allocation. The problems being faced in the country are not unique. Every country which has carried out power sector reforms like unbundling of integrated utilities, de-licensing of generation and open access, faced similar problems due to uncertainty in regard to development of generation and demand. In a changing scenario, approach of all stakeholders also needs a change. In a way, we are fortunate that the gaps between generation and transmission in our country have become apparent within a short span of time and corrective course of action is feasible. A comprehensive solution is therefore being proposed.

6.3.2 The proposed solution takes few points from GNA based system mooted by CEA and departs from the same in regard to sharing of transmission charges. The broad contours of proposed solution are given below:

- **i.** Transmission planning based on installed capacity with anticipated load and generation.
- **ii.** Transmission planning validation process, scenario based study and analysis and information sharing mechanism.
- **iii.** Amendments in Grant of Connectivity and Long Term Access Regulations in respect of Connectivity line and Exit option.
- **iv.** Transmission cost allocation based on usage.
- **v.** Transmission corridor allocation for short term open Access

6.3.3 The issue needs to be understood from the perspective of an IPP and drawee entity as it is emerging that commercial liabilities to pay for committed transmission charges drive the behavior of generation entities and drawee entities. They are not able to give their injection or Drawal requirement due to their structural and organizational issues. As the creation of transmission infrastructure is important for the growth of power sector and Indian economy, these deficiencies cannot be allowed to come in the way for planning and execution of Inter-State transmission system. Therefore, through a combined review of the Grid Code, Connectivity and Open Access Regulations and Sharing Regulations, it is proposed to take necessary regulatory steps with the objective of maximising evacuation of power from generating stations and minimising possibility of congestion based on appropriate design of the transmission system.

6.4 TRANSMISSION PLANNING

6.4.1 Transmission planning should be based on installed capacity with anticipated load and generation. This would ensure implementation of intent of the Act that all types of access should be accommodated. This will also ensure that there is no congestion on the injection side.

6.4.2 While formulating principle of transmission planning it should be considered that it may be better to plan for capacity higher than the requirement in view of the following:

- Transmission cost is only about 10% of overall cost
- Lack of transmission has severe consequences

6.4.3 *Transmission planning Process:*

6.4.3.1 CEA has pointed out the emerging dominance of generating capacity addition in the concept paper on GNA as under:

6.4.3.2 "The planning of transmission system to meet long term requirements of ISGS (Inter State Generating Station) projects is being carried out since 1975. In earlier time the ISGS only consist of generating stations of central sector companies i.e. NTPC, NHPC, NLC, NPCIL etc. Slowly, the predominance of central sector projects which have known beneficiaries (as determined by central government in the form of allocations) started fading out and now more and more of private sector generation projects (IPPs) are being envisaged. The current generation addition programme of 89 GW during 12th Plan has 47 GW under private sector as compared to only 26 GW under central sector.

6.4.3.3 The planning of transmission system for central ISGS was carried out with the prior knowledge of quantum of power, point of injection and point of drawal, and the problem of transmission congestion was then rarely experienced. Even for transfer of 15% unallocated power to different parts of the country, from time to time, there was rarely any problem of congestion because of the inherent margins built-up in transmission system to take care of additional power transfer of about 10-15% of transmission capacity.

6.4.3.4 The CERC Regulations for Open Access in Inter-State Transmission System (ISTS) were introduced in 2004. The Regulations had the provision for obtaining Long Term Open Access (LTOA) only and the information about the point of injection, point of drawal and the quantum were required to be furnished upfront. Even for obtaining connectivity, one was required to seek LTOA and commit for sharing of transmission charges.

6.4.3.5 As the IPPs found difficulties in finalizing beneficiaries at the time of LTOA application, CERC brought new Regulation in 2009 having separate provisions of Connectivity, Medium Term Open Access (MTOA) and Long Term Access(LTA). The regulation for Short Term Open Access (STOA) was also introduced separately through the 'Open Access in inter-State transmission Regulations, 2008' and supplemented by 'Power Market Regulations of 2010'.

6.4.3.6 The above regulations transformed the earlier philosophy of transmission planning for evacuation and delivery of power from ISGS which is now based on the provisions of Connectivity and 'LTA with target region' in the CERC Regulations. Large numbers of generation projects are coming up with no knowledge of firm beneficiaries. The situation is compounded by uncertainty in generation capacity addition, commissioning schedules and fuel availability. All these factors have made transmission planning a challenging task. Adequate flexibility has to be provided in the transmission planning to cater to such uncertainties, to the extent possible. However, given the uncertainties, the possibility of stranded assets or congestion cannot be entirely ruled out.

6.4.3.7 So the issue here is that from earlier Central transmission planning based on integrated resource planning wherein both points of injection and drawals and quantum of injection are known in advance, how to plan for the system wherein both these are uncertain not only in terms of quantum and point of injection but also in timeframe . On the one hand generation can get delayed due to execution risk and fuel uncertainty; on the other hand it may come early due to better construction technologies. Further Renewable generating plants which generally require less than 18 months gestation, have also to be considered while planning the transmission network.

6.4.3.8 On drawal side, the assumption may go wrong as demand projections based on Electric Power Survey (EPS) may not be realised as growth of overall economy, growth in a particular state or industry, as witnessed may be different from projected demand. Change in Drawal patterns may also be occurring due to change in nature/requirement of Open Access Customers and captive generators in the state selling power under open access. The problem of STU in estimating its Drawal requirement form ISTS must also be understood in this context.

6.4.3.9 Hence there is an urgent need to review the concept of transmission planning which, according to CTU and CEA, is based on Long Term Access. Before discussing international experience let us again refer to Staff paper of 2008, which brought out broad principle as under:

"1.*Powergrid, the CTU, has indicated that they have approved 26 cases of associated transmission systems for new generating stations adding to about 22,698 MW for long-term usage under CERC Open Access Regulations 2004. Another 27 applications aggregating to 11,187 MW generating capacity are under finalization and 48 cases amounting to 48,324 MW are under processing for creating of associated transmission systems. It is indeed a heartening development – a tangible outcome of the various reform and market development initiatives – that beckons us to quickly build the associated transmission system for delivery of power to the intended destinations.* ***Whatever be the commercial arrangements for sale of power, it is necessary to embrace all new generating stations in the transmission planning process so as to ensure timely evacuation of power matching with the generation addition program, through smooth coordination and practical commercial arrangements. "***

6.4.3.10 It is thus evident from this that intent was to embrace all new generating stations and make arrangement for evacuation of their power. Thus, **unless full plant capacity** (including overload capacity) is considered, it is not possible to create a reliable transmission system for its evacuation. It must not be lost sight of that a generating station is not only for the commercial benefit of the Generating company, it is being set up to fulfil power requirement of ultimate consumer. So the input for planning of transmission system cannot be made subjected to discretion of generator or its marketing strategy. The investment in transmission requires capital investment (sunk cost) for giving benefit for a substantially long duration of 25-30 years, decision on this issue need not depend on price of power to be sold under different type of contracts having short term commercial gains. The past assumptions that by seeking less LTA, generator is taking a risk at its own peril, is not a valid argument as investments in transmission are lumpy investments in blocks of capacity(say 500 or 1000 MW) and cannot be fragmented . Allowing a generator having installed capacity of 2000 MW an LTA of 400 MW and then trying to build a robust transmission system is like walking in the dark. Para 18 of the staff paper of 2008 aptly brought this out as under:

" *Generating companies making large investment in generating stations would not like the transmission system to become a bottleneck in evacuation of the station output. They would want an assurance in the* ***matter on a sustained basis.*** *Even if the size and location of a generating station and its beneficiaries are such that the incremental power flows could prima facie be accommodated on the existing system, it has still to be checked by the concerned STU/CTU that normal redundancy margins are not encroached upon in the process. This must be done sufficiently in advance, so that if the studies show any inadequacy in the system, time is available for carrying out the required augmentation. In case, this is not done in good time, the generating company may be required to restrict its generation, and it cannot claim a priority for use of the transmission system under "open access" or any* ***other provision, particularly if the generating company itself has been negligent in the matter. "***

6.4.3.11 So just because few players decide to play with fire and accept uncertainties in evacuation, the whole process of transmission planning need not change its basis of evacuation of installed capacity. Thus, it is evident that the transmission planning needs to be based on installed capacity and restricting it to LTA sought by generator is not a correct method. So whenever a generator seeks connectivity to ISTS it must be clear to him that the transmission system shall be built on the basis of its installed capacity and merely not declaring its LTA requirement correctly and not having identified beneficiary is not going to affect the planning process.

6.4.3.12 In this process we must understand the position of generator also. An entity making an investment of the order of Rs 5 Cr per MW will not shy away from paying 20-30 paise per unit of transmission charges. However, there may be tendency to avoid taking burden of payment of Long term transmission charges, if these charges are levied not on the basis of usage but on contracted power and under the prevailing uncertainties of power market, it is not allowed to change its Drawal points i.e. it is bound by permanent sink and source relationship. In the new dynamic scenario and in presence of a vibrant power market (in accordance with the objectives of Electricity Act and Policy), the planning of transmission system does not need a simple review but perhaps a paradigm shift to address the challenge of uncertainty in regard to generation as well as demand as now dispatch decisions are to be guided more by economic reasons.

6.4.3.13 In the recent past, the planning agencies have had a view that transmission planning on the basis of anticipated load generation scenario is difficult. This issue is detailed in the next section.

6.4.4 Transmission Planning based on anticipated flow:

6.4.5 CEA has further stated that the CERC has prescribed that transmission planning should be done purely based on anticipated flows. This is challenging task because of the following reasons:

(i) India is a vast country

(ii) There is high degree of uncertainty on realization of generation projects particularly in the private sector and the hydro sector

(iii) Power is concurrent subject and STUs have to be taken into the loop

(iv) The power drawal patterns of the States are not consistent

6.4.5.1 Point no. (i) and (iii) above present factual position. The issue at (ii) above is always encountered in a de-regulated power market and after 10 years of dealing this issue, a matured response based on experience of other countries in handling these uncertainties needs to be made. Once it is realised that a transmission service, which is regulated activity, has to respond through central integrated planning, solution emerges, it requires the planning process to be more consultative with increased interaction with Users.

6.4.5.2 International Experience in Transmission Planning under uncertainty:

It needs to be clearly understood that problems of transmission planning being experienced in India are not unique and all countries where Generation was De-licensed faced similar issues, as it gave detailed description of the issues being faced under Generation uncertainty. Some of the experiences and studies are given below:

(A) Future of Electric Grid , MIT Report[6]:

a. *The planning process in most ISO regions is significantly more difficult than within vertically integrated utilities because decisions about the installation of new generation are the result of market forces (modified by state and federal support for renewable and other policies) rather than centralized planning. Thus, transmission planning in these regions is subject to additional uncertainties about where future generation may locate and how power will flow around the network, especially when renewable generators are involved*.

b. *Magnifying this effect are uncertainties regarding future subsidies and requirements for generation, because a painful fact of transmission planning is that it typically takes much longer to plan, get approvals, and build a high-voltage transmission line than a wind farm or solar generating facility. When generator build times are shorter than those for transmission, planners are forced to either anticipate new generation and build potentially unnecessary infrastructure or wait for firm generation plans before starting the process and thereby potentially discourage new generation investment.*

c. *Planning issues:*
The scale and complexity of the Eastern and Western Interconnections are such that interconnection-wide planning requires a hierarchical approach encompassing bottom-up and top-down processes. Bottom-up planning is the process of integrating local or regional transmission plans that are based on detailed knowledge of local or regional conditions. Top-down planning involves a central body charged with identifying potentially desirable inter- and intraregional lines. Both have

[6] https://mitei.mit.edu/system/files/Electric_Grid_Full_Report.pdf

shortcomings: A solely bottom-up approach will fail to identify potentially desirable lines that traverse regional boundaries. To capture these potential investments, one needs top-down processes, performed as part of interregional and perhaps interconnection wide, planning exercises. But a purely top-down process may not be adequately responsive to regional issues or planning processes. A hierarchical hybrid of the two approaches has the potential to respect local and regional needs while still having vision broad enough to recognize interregional opportunities.

d. *Transmission Planning Methods*

Transmission planning involves discrete and long-lived modifications to complex networks in the face of an uncertain future. More technically, transmission planning is characterized by a large number of choices with multiple dimensions, a great deal of uncertainty, large investments, and long periods over which investments must be assessed. These characteristics are compounded and the challenges magnified when planning over larger areas and trying to achieve multiple objectives.

Restructuring and the ensuing separation of transmission and generation planning will increase uncertainty. As noted above, the impact of uncertainty surrounding plant location is often compounded by the mismatch between generation and transmission build times. Moreover, because load characteristics and locations, fuel prices, environmental policies, and generation portfolios may vary substantially over the 50-year lifetime of transmission investments, the network must be designed to perform well under a variety of different conditions. To evaluate a network design’s robustness, planners perform multi-period analyses under uncertainty, which allow them to consider investments that may not be deemed prudent during short time frames but may enable the efficient evolution of the grid in the long term. Performing such analyses for a complex network subject to multi-dimensional uncertainty is a computational and conceptual challenge, however, and little work has been done to develop methods to support robust network planning. Forward-looking studies often consider only the design of networks for a static year and single scenario. These analyses do not yield an optimal expansion path to the eventual desired network, nor do they consider robustness to situations in which the envisioned scenario does not unfold. Scenario methods, which consider multiple futures, have been used in some cases.

But scenario methods may not identify important regulatory and other uncertainties regarding the availability of renewable resources.

Because increased uncertainty cannot always be dealt with adequately via deterministic or scenario processes, stochastic planning criteria, tools, and methods will need to be developed by the industry and the research community, and then employed.

(B) *Transmission Grid Planning in Modern Electricity Markets :Elforsk*[7]

a. *"Over the course of the past 20 years, many countries have liberalised their electricity industries. The historically vertically integrated electricity industry has been broken up into four parts: generating companies, transmission and distribution network service providers, and retailers. Reliance has been placed on the forces of competition to achieve efficient operational and investment decisions by generators, while the operational and investment of the transmission and distribution networks have been placed under the responsibility of grid operators. Achieving overall efficient outcomes in this context requires efficient investment by the regulated transmission network service provider as well as close coordination between generation and transmission investment. The determination of the optimal sequence and timing of transmission network investments is known as the transmission planning problem. Transmission planning is complex, involving consideration of the impact of a transmission augmentation under a large number of future demand and supply scenarios. In principle, the transmission planning problem is well understood in the context of a vertically-integrated electricity industry. In this context, a transmission augmentation has the following primary benefits: It allows for more efficient dispatch (allowing for lower cost remote generation to be used in place of higher cost local generation); it allows inefficient investment in generation to be deferred; and it reduces the need for operating reserves by allowing those reserves to be shared over a wider area. In principle, if the liberalized electricity market is sufficiently competitive, the same tools and techniques that have been*

[7] http://www.elforsk.se/Documents/Market%20Design/projects/ER_13_73.pdf

developed for transmission planning in the context of an integrated electricity industry can be applied. However, two new issues arise:

(i) The first is coordination between generation and transmission investment. How should transmission and generation investment be effectively coordinated?

(ii) The second issue is the problem of generator market power.

b. At the theoretical level, there are just two broad approaches in regard coordination of generation and transmission investment, which have been referred to as the "proactive" approach and the "reactive" approach. Under the proactive approach, the transmission planner "moves first", taking into account information on all possible generation opportunities including location, technology, and capacity decisions and network expansion costs, and chooses the most efficient network. The generation companies then make their investment decisions taking the transmission network as given. This approach places a great deal of reliance on the efficiency of the planning task. In principle, if the transmission planner has information on all possible generation opportunities, and if more efficient generation can displace less efficient generation in congested locations, this approach will yield efficient coordination of generation and transmission decisions. Under the reactive approach, the transmission company does not require knowledge of all possible generation opportunities. Instead, the transmission company simply follows a policy of augmenting the transmission network when the forecast congestion costs exceed the cost of augmenting the network. Under this approach, generation companies "move first", selecting investment locations, technology, and capacity. The transmission company responds by augmenting the network when forecasted congestion exceeds the threshold. This approach can also yield efficient coordination of generation and transmission investment, provided there is implemented a system of charges for use of the transmission system which reflect the fixed costs of upgrading the transmission network in response to generation investment locations decisions."

c. *The long-term efficient growth and development of the electricity industry requires close coordination between generation and transmission investment. In the absence of an assurance of timely and adequate transmission investment, generation companies will be reluctant to expand or invest in locations which lack adequate capacity of the transmission network to "evacuate" that power, even when those locations are the most efficient sites for new generation overall. On the other hand, the threat of inefficient (or excessive) transmission investment can have a chilling effect on efficient generation investment.*

d. *However, in the most liberalized electricity markets, responsibility for generation and transmission investment decisions have been placed in separate entities. Transmission investment decisions are evaluated and carried out by regulated transmission network operators. Generation investment decisions, on the other hand, are evaluated and carried out by large number of independent, unregulated generating companies. How can we be sure that the decentralized decisions of generation and transmission entities will ensure an efficient development of the industry - that is, the most efficient configuration of the transmission network and the most efficient capacity and mix of generation at all locations on the network and at all points in time? "*

The point is emphasized by Brunekreeft and Leveque[8],

e. *"Electricity liberalization brought, among others, a profound change in the terms of investment in both generation and transmission. Decisions concerning the construction of new power plants, in particular the timing and the technology mix (i.e. the proportion of hydroelectricity, nuclear, thermal, etc.) now depend on decentralized initiatives of investors and not on public authorities. As for transmission, which remained a monopoly, the reinforcement and expansion of high-tension power lines are no longer directly controlled by generators. ... In short, investments in an electricity system that is open to competition will no longer be coordinated by the*

[8] L. Brunekreeft,"Investment in generation and transmission "Competition and Regulation in Network Industries,Vol. 2.no.1 ,p.3,2007

same mechanisms as in the past. The planning that enabled a monopolistic and vertically-integrated producer to adjust base and peak capacities, as well as generation and transmission capacities has been replaced by a series of decentralized decisions based partly on prices. Ideally, an optimal level of investment in the electricity system would improve joint optimisation of investments in generation and transmission. Of course, coordination between generation and transmission was theoretically possible when both tasks are the responsibility of the same entity - as was the case when generation and transmission were both part of a vertically-integrated entity. This type of coordination will be used as a benchmark in our study in this report. This leaves us with two possible approaches for coordination between generation and transmission capacities: (1) The "proactive" approach, and (2) The "reactive" approach. After detail modeling and computation of consumer surplus the report concludes:

f. *The numerical results in this paper approve the theory behind three different ways of coordinating the generation and transmission investment decisions. The efficient coordination result in best outcome but it is impossible to implement the efficient coordination in liberalised power markets. The proactive coordination is the second best. In the proactive coordination, the transmission planner moves first and plans the future transmission system. The generation companies take the augmented transmission system and locate their new generation facilities. The only barrier in this method is the volume of information needed by the transmission planner. It is unlikely that a company can have this volume of information.*

g. *The reactive coordination is the third-best and it is close to the real-life approaches used by several transmission system operators. In the reactive coordination, the transmission planner does not need to have full information about future generation system. The transmission planner monitors the status of the transmission system (using metrics such as congestion cost) and augments the system if needed.*

h. *This report does not intend to recommend or reject any of these two approaches but it aims at providing mathematical tools and numerical* *results for analyzing these two approaches for coordinating investments in transmission and generation capacities. The developed numerical tools can be used by TSOs and regulators to give more insights to these approaches."*

6.4.5.3 It is expected that clear regulatory intent of transmission planning based on installed capacity in-place of LTA would take care of most of the planning and system operation issues. It will help in minimising congestion in evacuation of generating stations as all type of access are proposed to be accommodated in the network. Pro-active participation of STUs and Discoms in transmission planning will help in addressing demand side issues related to planning and operation of ISTS.

6.5 PROPOSED METHODOLOGY OF TRANSMISSION PLANNING:

Validation Process, Scenario based study and analysis and Information Sharing Mechanism

6.5.1 Draft National Electricity Plan published by CEA in 2012 and minutes of Standing Committee meetings have been analysed for this purpose. The process of planning of inter-State transmission need to be made broader based and certain Regulatory instructions are required to make the process more participative.

6.5.2 As inter-State transmission system planner, planning agencies base their planning on drawal from and injection into inter-State transmission system. On a macro level, the Peak Demand and Energy Requirement figures in respect of States/UTs give a broad estimate in regard to these. However to make it more accurate it is proposed to include provisions in this regard in the Grid Code.

6.5.3 In order to facilitate informed decision making by all stakeholders like STUs and generators planning to take location decision, following plan is proposed.

a. CTU shall publish load -generation balance for different scenarios for next three-five years in consultation with CEA and POSOCO.
b. State Transmission Utilities shall submit their next five year injection and drawal estimates to CTU and CEA in the format prescribed under the Grid Code. This shall be done on the rolling basis in the month of January every year for the next five financial years. Necessary format for providing the information shall be developed in consultation with CTU and CEA. There shall be five year rolling transmission plan. All

the entities seeking connectivity to ISTS shall be required to submit information to STUs by January every year and this will be considered as final for next financial year. During the year no new request for connectivity or Access shall be entertained during the ensuing financial year.

c. The Planning agencies shall inform the Commission, in case information is not filed by concerned STU so that necessary action for non compliance of Commission's direction may be taken.
d. A validation committee similar to the one constituted under Sharing Regulations shall be incorporated in the Grid Code for this purpose
e. The validation committee shall take into consideration the data submitted by STUs. The committee shall take trend of injection and drawal from the ISTS from the implementing agency in respect of Point of Connection Charges for last two years. Based on this, a profile of ISTS injection and drawal for next five years shall be prepared every year in the month of March. The validation committee of CEA, CTU, System Operator (POSOCO) and all STUs shall finalise this transmission system requirement profile and approved transmission system requirement profile shall be published. This document shall be published on the web site of CTU for comments of stakeholders.
f. As there is a need to integrate power system operation and power market with transmission planning, an annual statement showing injection and withdrawal from existing bid areas shall be published by CTU.

g. Final document shall form the basis of transmission planning in the country. The Standing Committee for System Planning in each Region while formulating or modifying a transmission scheme shall take this document as reference.
h. The STUs shall be kept informed by respective Load Despatch Centre on quarterly basis about the deviations of actual Drawal of entities from the ISTS as compared to their projections. If deviation was found persistent, necessary action may be initiated by STU against the concerned utility/entity.
i. As only injection and drawal data shall not be sufficient for transmission planning process, complete data about network along with planned addition of generation and load within the STU area shall be given by all users/entities to STU in January every year .STU may in consultation with their SERC formulate penalties to handle

deviation from estimated generation and demand in their area. STUs need to submit consolidated data within their area to CTU to enable it to do optimum planning.

j. It is proposed to devise regulatory compliance of data submission for transmission **planning in line with FERC Form No. 715 [9]- Annual Transmission Planning and Evaluation Report**. A copy of this is enclosed at **Annexure- XV**. The format shall be finalised by CEA and CTU in consultation with the stakeholders. Commission will issue necessary order for its implementation.

k. Network data in suitable format shall also be published by CTU & POSOCO for the All India transmission network. The access to this data to authorised entities shall be based on 'credential control through username/password.

l. For every transmission system planned and proposed three possible scenarios of expected load and generation (Normal, optimistic and pessimistic) shall be given. The transmission system shall also be proposed for three possible scenarios and consequences of opting for any particular transmission system shall be elaborated. The consequences shall include benefit identification and present and future requirement to be catered by the proposed system. Possible cases of congestion in case of opting for a particular scenario must also be brought out clearly. In this connection future generation load growth along with pocket of possible ROW problem need to be brought out clearly.

m. After firming up a transmission system, an Environmental Impact Assessment (EIA) shall also be brought out for consideration of all stakeholders and if required re routing of proposed transmission system must be done to make minimal environment impact. Input from other government agencies may be taken at the planning stage itself, like status of clearances etc to avoid future problems in execution of the scheme.

6.5.4 CEA also has recently sought comments of stakeholders on Planning of Transmission System. On this, POSOCO submitted its detailed submission. Copies of these documents are enclosed at **Annexure-XVI & Annexure- XVII** respectively.

[9] http://www.ferc.gov/docs-filing/forms/form-715/overview.asp

6.6 Amendment to Grant of Connectivity and Long Term Access Regulations in respect of Exit Option.

6.6.1 Exit option

Regulation 18 of Connectivity Regulations provides for relinquishment of Long Term Access Right by a user as under:

18: Relinquishment of Access Right:

(1) A long-term customer may relinquish the long-term access rights fully or partly before the expiry of the full term of long-term access, by making payment of compensation for stranded capacity as follows:

(a) Long-term customer who has availed access rights for at least 12 years.

(i) Notice of one (1) year – If such a customer submits an application to the Central Transmission Utility at least 1 (one) year prior to the date from which such customer desires to relinquish the access rights, there shall be no charges.

(ii) Notice of less than one (1) year – If such a customer submits an application to the Central Transmission utility at any time lesser than a period of 1 (one) year prior to the date from which such customer desires to relinquish the access rights, such customer shall pay an amount equal to 66% of the estimated transmission charges (net present value) for the stranded transmission capacity for the period falling short of a notice period of one (1) year.

(b) *Long-term customer who has not availed access rights for at least 12 (twelve) years – such customer shall pay an amount equal to 66% of the estimated transmission charges (net present value) for the stranded transmission capacity for the period falling short of 12 (twelve) years of access rights*

6.6.2 Apparently the above Regulatory mechanism was conceived based on situation that after commissioning of plant , if due to some reason Generator wants to exit its Long Term Access, there would be some business entity (Going Concern principle of Accounting practices) to pay for the transmission system which has already been developed . However, what will happen if generator failed to put-up its plant and Applicant has simply vanished, construction bank guarantee in such case would be inadequate .The Force majeure clause in BPTA is providing them escape route or litigation opportunity to delay the process of recovery of Exit charges. This is the maximum risk scenario that either transmission licensee has revenue gap or other users of the ISTS need to pay for this stranded or underutilized asset.

6.6.3 CTU in 2009 proposed construction of High Capacity Transmission Corridors for various IPPs as transmission system required for evacuation of power from these generators was based on their target region . When a few of these IPPs in 2013-14 started requesting for surrender or reduction of their LTA , CTU expressed difficulty in identifying stranded transmission capacity and proposed some alternative mechanism like charging for a fixed MW capacity in case of relinquishment of Long Term Access.

6.6.4 In an environment of delicensed generation on one side and unbundled drawee state entities on other side, which is not ready to commit for planning and construction of transmission system , there is lot of uncertainty in the utilization of transmission system . In such a situation the issue of relinquishment of long term transmission access by generators has very complex implications in the form of underutilized transmission system and payment of transmission system created for anticipated generation needs to be ensured. Therefore before formulating a solution for this , it is necessary that all aspects of the problem are discussed in a comprehensive manner.

6.6.5 The Regulatory mechanism provided under Connectivity Regulations 2009 was premised on of mutual trust and timely information sharing.

6.6.6 *In this context experts from a Mckinsey Global Institute Report : Infrastructure productivity[10]: are reproduced hereunder:*

"We find that effective infrastructure governance systems share six traits:

- *Close coordination between infrastructure institutions*
- *Clear separation of political and technical responsibilities*
- *Effective engagement between the public and private sectors*
- *Trust-based stakeholder engagement*
- *Robust information upon which to base decision making*
- *Strong capabilities across the infrastructure value chain*

6.6.7 *In view of transmission project investment which are block investment and sunk* investments and also taking in view the constraints being faced in financing infrastructure investment ,following issues of uncertainties on the Generator side need to be handled carefully so as to avoid or minimize the underutilized transmission assets.

1. Delay in commissioning of Generator due to legal and statutory issues
2. Change in anticipated customers or target regions
3. Abandoning or shelving of the projects due to legal or fuel issues.

6.6.8 It is to be noted that GNA concept while addressing the operational issue of congestion , connectivity without LTA etc is not fully addressing these issue which are also have a significant bearing on consumers , who are ultimately going to pay for the assets planned for implementing GNA**.** While generators are seeking exemption from the condition that atleast three year in advance target customers need to be informed as per **Connectivity** Regulations and procedures for execution of transmission projects, they are not suggesting how the above mentioned issues can be addressed. The presence of PPA was providing a comforting balance both about certainty of execution and payment of transmission charges from beneficiaries, although it may be agreed that case 1 bidding uncertainty is not in control of generator.

[10] http://www.mckinsey.com/~/media/McKinsey/dotcom/Insights%20and%20pubs/MGI/Research/Urbanization/Infrastructure%20productivity/MGI_Infrastructure_Full_report_Jan2013.ashx

6.6.9 Earlier the transmission projects were being developed through cost plus system where the progress of generating stations and transmission projects can be matched to a certain extent based on coordination and there were certain mechanisms like implementation agreement, etc., wherein the liabilities in cases of delays were identified and addressed. The scenario was also different due to pre identified beneficiaries of generating stations and transmission projects were initiated based on BPTA signed with these beneficiaries. The investment in transmission projects now being done through competitively bid projects which once take off cannot not be slowed down, held back and once commissioned, the tariff needs to be given.

6.6.10 The issue of relinquishment has become very complex in such a scenario. Although the existing Connectivity Regulations have provision of payment of Exit charges based on Stranded capacity, past few years' experience indicates that the provisions of Connectivity Regulation which were formulated to promote investment in generation and to facilitate a conducive environment were not used in the right sprit and some generators after seeking connectivity and long term access are trying to offload their risk to other stakeholders like transmission licensee and existing customers (DICs). This sometimes results in creating the uncertainties in the whole transmission planning, project execution and transmission cost allocation process,. The existing bank guarantees are not found sufficient to handle the risk when transmission projects were initiated at the request of generating projects and later they abandon the projects. The case of marginal shift in rescheduling of generation can be handled through Regulatory mechanism but cases of abandoning or downsizing of generation projects are difficult due to two reasons firstly the onus of quantifying the stranded capacity falls on CTU and this can be contested both on quantity and duration and secondly there may be cases where the generation project developer disappears and no one is available to whom the liability can be billed.

6.6.11 Also there is no doubt that this shifting of risk from one player to another happened not only due to risk in regard to land , water , environment and forest clearance but also due to non-participatory or non-committal role played by other stakeholders in transmission planning and investment decision process.

6.6.12 The issue was discussed with planning, operating agencies and stakeholders . Suggestions on both sides of spectrum were received. While some suggested to put all liabilities on generators before initiating the execution of Commission projects and seek upfront payment of full or part capital cost or commensurate bank guarantees, some suggested review of stranded capacity and delinking it with stranded capacity and link it to some predetermined Point of connection charges for say three to five years.

6.6.13 CTU recently in its letter dated 20.5.2014 on the subject determination of compensation towards relinquishment of LTA due to change in region by various IPPs suggested following:

> " 11. Keeping the above in view , it would be prudent that the compensation for relinquishment of LTA may be calculated on the basis of fixed quantum in MW in place of stranded capacity."

6.6.14 Further to this, CTU in its letter dated 28.7.2014 to Secretary ,CERC proposed to increase construction bank guarantee from Rs. 5 lakhs to Rs 50 lakhs per MW. It also suggestion a framework for dealing with Exit and delay in commission of generating stations. A copy of letter is enclosed as Annexure- **XVIII** .

6.6.15 As a normal regulatory contest it was found that every stakeholder has its own perception and wants to minimize his risk . Each stakeholder is looking into the issue with its own perspective.

" When I become a journalist I was taught that there were two sides of every story .But I find there are four or five sides of a story". Alistair Cook , BBC.

6.6.16 During the discussion with central transmission planning agencies, two views emerged regarding commitment from IPPs which at the time of application for access have no identified beneficiaries i.e. not having long term PPA. It was expressed by them that present bank guarantee is far too inadequate for comfort in constructing transmission system.

6.6.17 One view is that before creating a transmission system for these generators, they should deposit cost of transmission system to be developed. This view was based on the fact that as transmission system cost is only a small fraction of generating station cost.

6.6.18 Another view is that instead of binding the Generator for payment of transmission charges for 12 years it can be asked to pay upfront one year transmission charges (based on average injection and withdrawal charges) and bank guarantee corresponding to 2 years transmission charges.

6.6.19 It was also opined that at present due to non availability of any Force Majeure clause, Generators hesitate to enter into transmission agreement (Bulk Power Transmission Agreement or Transmission Service Agreement) corresponding to its capacity. Planning and execution of a generating station depends on many external factors and it may be better to provide a suitable mechanism and time slots for exit.

6.6.20 On this issue a balance needs to be found that due to such exit, stranded transmission system is not created and burden is not transferred to other users of transmission system. If this option of allowing generator an exit after commencement of transmission system implementation is considered, risk is transferred from generator to existing users. Mechanism to absorb these risks may be found without creating any regulatory assets. The role of central planning agencies is very important in this regard as they have to coordinate not only with generators and transmission system developers agencies to avoid any such incident but also in planning, if such incident happens planning; needs to be modified to accommodate such incidences so as to increase utilisation of these system.

6.6.21 As in India we need investment in generation to make affordable power available to all, we also need investment in transmission optimally so that assets are utilized in an efficient manners and infrastructure financing can be done for all sector of economy, without a sector crowding out other sectors . The much quoted example of roads, where sometime economic development follows project execution, cannot be fully applied on transmission sector because development on connecting nodes may not follow same pattern if expected or projected generation and load did not materialize on source and sink. The opening of lines on high voltage is indication of this mismatch and it cannot be continued for a long period as it affects system reliability.

6.6.22 While formulating concept paper on the issue one approach was to see whether some amendments in existing Regulations are sufficient to address the issues being faced or to adopt a holistic approach to see the entire process of transmission planning and implementation need to be back afresh. It was found prudent to start discussion on all aspects and it is proposed that a phased approach of amendments will be done based on comments. Few amendments may be done in first phase and later more issues may be taken care. The change in approach is required to integrate more renewable power into the grid . While the conventional transmission investment were based on generation capacity addition (Evacuation schemes) and reliability investment (Regional up-gradation) , the transmission for renewable would require Active Policy support investment where to implement government policy of Renewable Energy , transmission investments are required to be made. To arrive at judicious decision about liabilities to be assigned to Generator seeking connectivity and LTA it is necessary that the policy and regulatory frame works in other countries are also examined regard to of transmission planning and recovery of transmission charges.

6.6.23 Although following discussion is more relevant in the context of renewable energy, Indian System where plant location is decided more by fuel availability, it is also relevant in case of Large Generation. Future policy Organization , European Union suggest following:

Who pays the cost of connecting and reinforcing?[11]

In deregulated generation scenario the investment for transmission for upcoming generating projects is basically divided into two areas:

1. *Shallow connection – Connectivity of generator to nearest grid point or pooling point.*
2. *Deep Connection- Network upgrades required in large grid network to enable power flow from pooling point to load utilities with compliance of existing Reliability Standards.*

[11] http://www.futurepolicy.org/2561.html

Shallow connection charging

The shallow method of connection charging minimizes the costs for producers, and allows the expected cost of their projects to be estimated at an early stage. We highly recommend this method.

If you apply this method:

producers will pay for the costs of the equipment needed to connect their plant physically to the nearest point of the electricity distribution grid; and

grid operators will pay any costs for reinforcement of the network - costs which are passed to the final consumer by including them in the system charges.

The advantage of this method is that producers will tend to choose the location for their renewable energy plants based on resource, not grid, availability. The disadvantage is that this could cost more if grid extensions are needed for the best resource locations.

For example, the shallow method of connection charging was enacted in Germany.

Germany Renewable Energy Sources Act 2004, Article 13 provides that:

(1) The costs associated with connecting plants generating electricity from renewable energy sources or from mine gas to the technically and economically most suitable grid connection point and with installing the necessary measuring devices for recording the quantity of electrical energy transmitted and received shall be borne by the plant operator. In the case of one or several plants with a total capacity of up to 30 kilowatts located on a plot of land which already has a connection to the grid, this plot's grid connection point shall be deemed to be its most suitable connection point; if the grid system operator establishes a new connection point for the plants, he shall bear the resulting incremental cost. Implementation of this connection and the other installations required for the safety of the grid shall meet the plant operator's technical requirements in a given case as well as the provisions of Article 16 of the Energy Industry Act. The plant operator may have the connection and the installation and operation of measuring devices implemented either by the grid system operator or by a qualified third party.

(2) The costs associated with upgrading the grid in accordance with Article 4(2) that solely result from the need to accommodate new, reactivated, extended or otherwise modernised plants generating electricity from renewable energy sources or from mine gas for the purchase and transmission of electricity produced from renewable energy sources shall be borne by the grid system operator whose grid needs to be upgraded. He shall specify the required investment costs in detail. The grid system operator may add these costs when determining the charges for use of the grid.

However it can be mentioned that this shallow charging mechanism is applied to Renewable Generation as public policy initiative of promoting renewable generation.

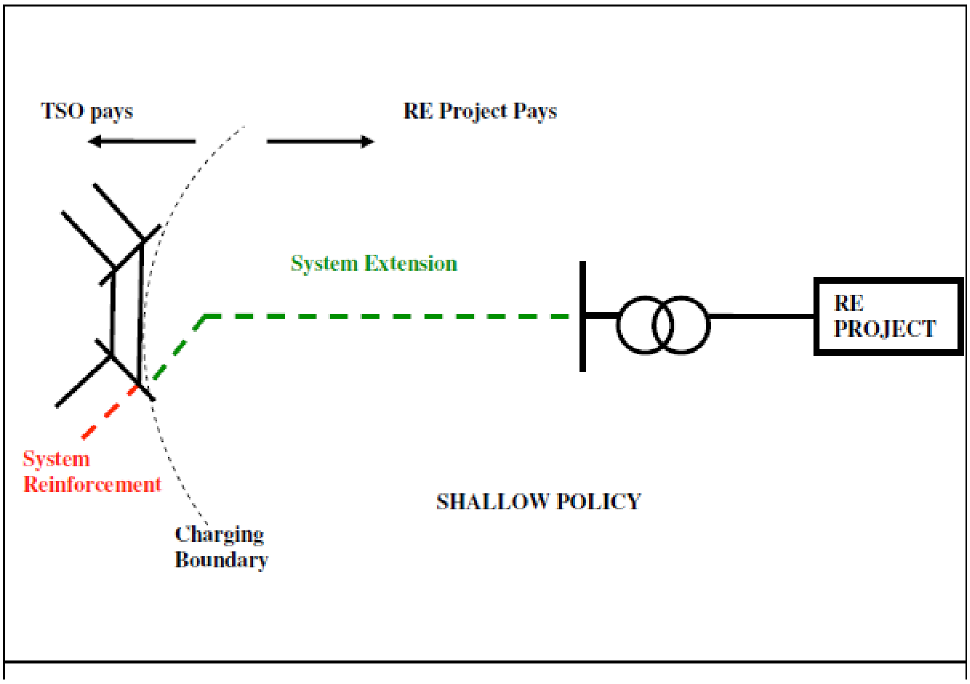


Figure 5- Shallow Connection

(*Reference: XERO Energy ,August,2007* European practices with grid connection, reinforcement, constraint and charging of renewable energy projects)[12]

Deep connection charging

The deep method of connection charging puts higher costs on producers. Experience has shown that this charging method is one of the major barriers to increasing electricity production from renewable sources, and so we do not recommend this method.

If you apply this method:

Producers will pay for the costs of the equipment needed to connect their plant physically to the nearest point of the electricity distribution grid, plus all the cost of any network reinforcement necessary to connect their plant, grid operators will pay nothing.

The advantage of deep connection charging is that it provides an incentive to produce green electricity at locations where grid connection costs will be lowest, thus lowering cost for the electricity system as a whole. The disadvantage of this approach is prohibitively high connection costs that might hamper the rapid deployment of electricity produced from renewable energy sources and discriminate against renewable producers.

[12] www.ontario-sea.org/.../1978_**EU-practices-grid-connection**_2007.pdf

Mixed or shallower connection charging

The mixed or shallower method of connection charging combines the shallow and deep methods. This approach can be seen as a "compromise" between the two objectives of giving some locational incentives and reducing the burden on the producer to pay grid reinforcement costs.

If you apply this method:

Producers will pay for the costs of the equipment needed to connect their plant physically to the nearest point of the electricity distribution grid; and

Producers and grid operators will share any possible costs of grid reinforcement, with producers paying usually an amount based on an assessment of their proportional use of the new infrastructure. In this case it is especially important that the rules to calculate the costs covered by each party are clear and not discriminatory.

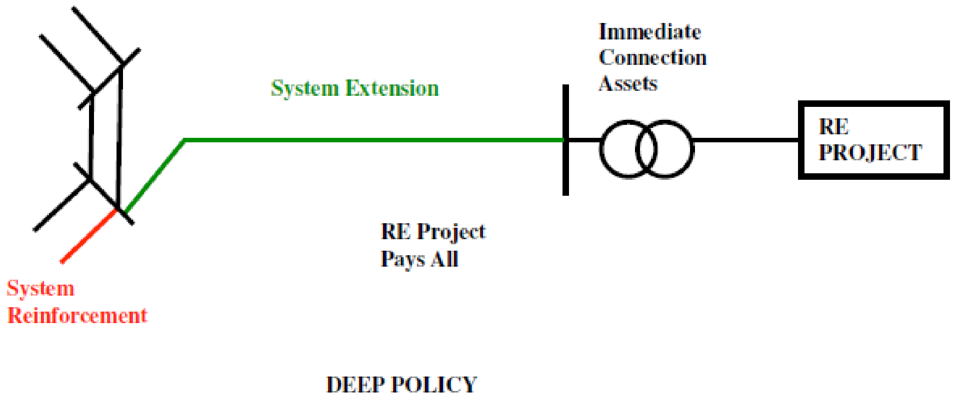


Figure 6-Deep Connection

(Reference: XERO Energy ,August,2007 European practices with grid connection, reinforcement, constraint and charging of renewable energy projects*)*[13]

There are few more variations or combination of Connections:

[13] www.ontario-sea.org/.../1978_**EU-practices-grid-connection**_2007.pdf

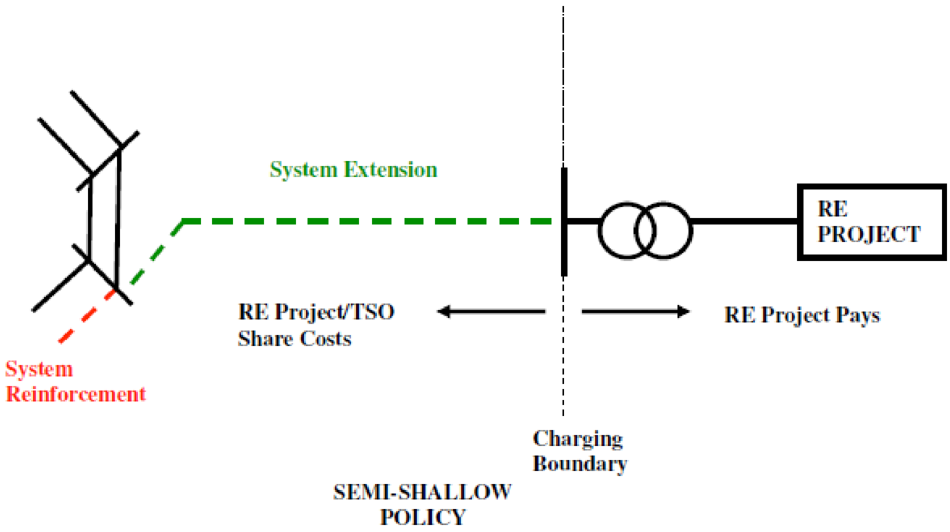


Figure 7-Semi Shallow Connection

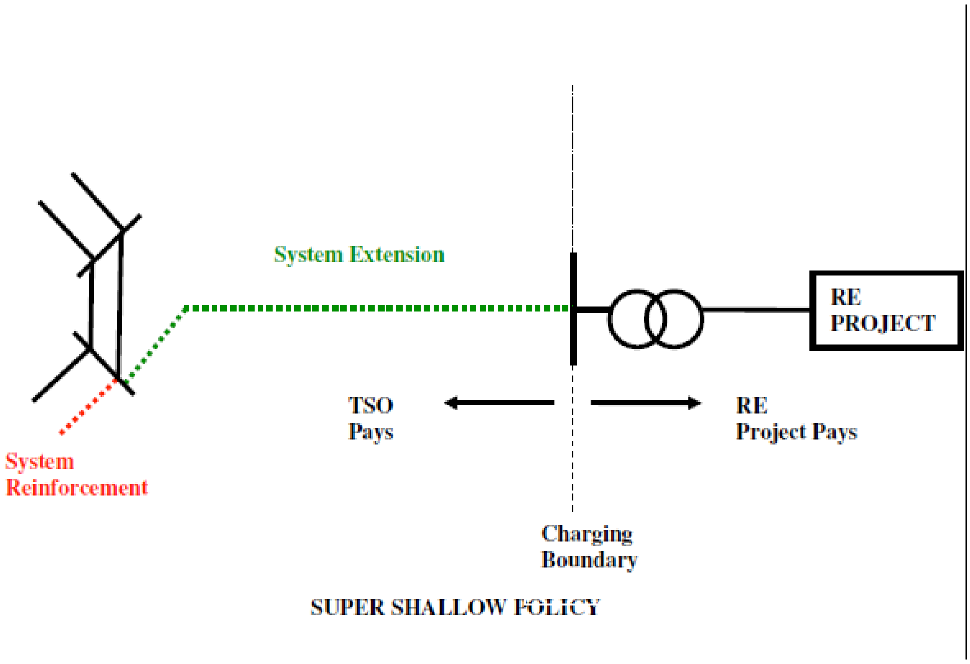


Figure 8-Super Shallow Connection

(Reference: XERO Energy ,August,2007 European practices with grid connection, reinforcement, constraint and charging of renewable energy projects*)*[14]

6.6.24 **Survey of international practices**:

[14] www.ontario-sea.org/.../1978_**EU-practices-grid-connection**_2007.pdf

As per study by Cambridge Economic Policy Associates , commissioned by ofgem, UK in March,2011 Review of International models of Transmission Charging arrangement –

Table A2.4: Type of Operational/Transmission Use of Charge for electricity [15]

Country	***Connection charge –***	***Who pays?***
Great Britain	*Shallow*	*• Connecting parties pay for the cost of connecting a party to the grid, including the cost of particular assets that can only be used by that party.*
Europe		
Denmark	*Shallow to partially shallow*	*• For certain types of generation technology the connecting party only pays the cost of connection to the 10-20 kV grid system. However, if the generation plant owner chooses a higher voltage then they are responsible for meeting this cost.*
France	*Shallow*	*• Connecting parties are required to pay the cost of connection to the grid network and also for any network reinforcements at the connection voltage.*
Germany	*Deep (customers); Shallow (power plants)*	*• Under the Renewable Energy Law in Germany, plant operators pay for the costs of connecting plants to the grid and for the related appliances.* *• Costs for upgrading the grid due to newly connected plants are paid by the grid operator. These can be passed on in the use of system fees.*
Ireland	*Shallow to Partially Deep*	*• Connecting parties pay for connecting to the grid. The method used is based on the Least Cost Technically Acceptable shallow connection method. This means the cost depends on the availability of appropriate transmission infrastructure.*

[15] https://www.ofgem.gov.uk/ofgem-publications/54334/ofgem-transmission-charging-review-final-report.pdf

Country	***Connection charge –***	***Who pays?***
Italy	*Shallow*	*• The connecting party has responsibility for costs arising directly from the connection with the new plant. • Additional network reinforcement is paid by the network operator but only in the case that the connection is shared amongst a*
Netherlands	*Shallow to partially shallow*	*• Connecting parties with connections up to 10MVA are shallow, however, connections over 10MVA need to be negotiated on a case-by-case basis.*
Northern Ireland	*Shallow*	*• Connecting parties pay for connecting to the grid. The method used is based on the Least Cost Technically Acceptable shallow connection method. This means the cost depends on the availability of appropriate transmission infrastructure.*
Norway	*Shallow*	*• Connecting parties pay an investment contribution for the cost of connecting new customers to the network.*
Spain	*Shallow*	*• Connecting parties make an upfront payment for the connection cost, including network reinforcement. However, if new users connect within a period of 5 years they are required to make a pro-rata payment for the costs.*
Sweden	*Deep*	*• Connecting parties pay deep connection charges when connecting to the grid.*
US		
California	*Shallow*	*• Connecting parties pay the shallow connection costs of joining the network.14*
New England	*Shallow*	*• Connecting parties are not responsible for any reliability network upgrades that result from their connection. 15*

Country	Connection charge –	Who pays?
New York	Shallow	• Connecting parties are not responsible for their impact on the reliability of the system hence the system has been classified as having shallow connection costs.16
PJM	Deep	• Connecting parties pay deep connection costs. This is to ensure that PJM's reliability is not adversely affected by the new connection.
Texas	Shallow	• Texas is not subject to FERC regulation but has adopted similar measures and hence connecting parties are subject to shallow connection charges.
Latin America		
Argentina	Shallow	• Connecting parties pay a charge to cover the operating and maintenance costs.
Chile	Shallow	• Connecting parties pay a charge for the cost of the operating equipment that links them to the transmission system
Australasia		
Australia	Shallow	• Connecting parties pay only for the connection assets they require to connect to the grid. • Where a generator requests an augmentation that is not justified on the basis of producing a net economic benefit or on the basis of reliability, then the generator may pay for the augmentation.
New Zealand	Shallow	• Connecting parties pay for connection assets needed to connect to the network. Connecting parties do not pay for augmentations to the core grid that arise from their connection.

Table 6: Survey of Transmission Connection System: International Practices

6.6.25 Professor Ignacio J. Perez-Arriaga in his presentation[16] mentioned that the discussion whether Generator or load should pay transmission charges always leads to two extremely opposite points of views

a. As it is the generator which seeks access to market , it should pay for the transmission system.
b. It is the demand customers to whom the product needs to be delivered, hence they should pay for the transmission system.

6.6.26 The position taken by stakeholders would depend on situation, In a country facing power shortage would try to encourage investment in Generation and demand customers would readily agree for transmission system (Pre 2007 scenario) . Once power situation become comfortable or it is perceived that as generators are making profits , demand customer opine that generator should also be asked to pay for transmission system.

6.6.27 So at present transmission system is built when Generator is ready to commit for payment of transmission charges so cost of transmission system cost is also attributed to him so when it sought EXIT , transmission charges for stranded capacity are asked. In present system where liability of generator to pay transmission charges is till it finds its long term beneficiaries is a somewhat balancing act.

6.6.28 From demand customer there is no commitment for payment unless it asked for LTA , which is normally sought by Generator. There are many instances in the past where transmission system could not be utilized fully due to absence of downstream system.

6.6.29 In an ideal situation specifically for a developing country like India , if an integrated approach of planning with active participation from all stakeholders is followed then Central Planning agencies may be asked to follow mandate of National Electricity Policy and plan and implement the transmission system keeping in view the future generation and load and this expansion need not be assigned to a particular generator or load. Interestingly while this approach is adopted for Green corridor projects and all agencies (CEA, CTU, STUs, Ministry of Power and MNRE) agreed, this is not being adopted for Large IPP generators. Probably the

[16] ocw.mit.edu/...**electric-power**.../MITESD_934S10_lec_16.pdf

fear of past experience alongwith ownership of these IPP is an area of concern; otherwise similar problems of delay in commissioning of generation , change in customers and sometime abandoning of projects happen for Central and State sector projects also.

6.6.30 Another business-like approach which is adopted in USA as per Large Generator Interconnection Procedure (LGIP)[17] and Large Generator Interconnection Agreement (LGIA) is that for avoiding any stranded transmission investment due to uncertainty of generator , sufficient upfront payment is taken from Generator till commissioning of the generating station. This initial payment is adjusted with interest in first five years of transmission system tariff to be paid by generator. Also at the time of exit it is the responsibility of generator to find alternate user of the system, till then he will be liable to pay transmission charges. The above system wherein Generator is asked to pay for capital cost of transmission is based on FERC decision on 24th July, 2003-Docket No. RM-02-1-000 order No. 2003 for Standardization of Generator Interconnections Agreements and Procedures .[18]

6.6.31 So there is a need to formulate Regulation, procedures and agreement to enforce contractual obligation. Also it is felt that present bank guarantees are not sufficient for grant of connectivity and long term Access. As the bank guarantees are not a cash burden and financial institutions providing bank guarantee on the basis of assets of applicant generator play additional role of monitoring the progress of project, these can be enhanced

6.6.32 Although the most justified approach should be that commitment is sought from both the sides and only for left out portion i.e for (∑Generation GNA- ∑Demand GNA) generator is made responsible.

6.6.33 The principle of Ramsey Cost Allocation may be applied for cost allocation among demand ultities and generator i.e cost can be attributed based on inelasticity of demand for grid access. Many European countries follow this methodology.

17 https://www.ferc.gov/industries/electric/indus-act/gi/.../2003-C-**LGIP**.doc

18 http://www.ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp

6.6.34 Another variation can be used for cost attribution that if generator is coming in high demand area or its presence is relieving congestion then less cost should be attributed to him and if there are many generators in queue to replace the generator in a particular area . This cost attribution can be used for computing the EXIT or relinquishment charges. So the period of 12 year can be relaxed accordingly.

6.6.35 Hence if mandate of electricity policy need to be followed, transmission planning cannot be let to be driven solely by LTA/GNA requirement given by users.

6.6.36 "Creating incentives for transmission system investment and innovation to congestion and expand the scope of the competitive market is a central issue in electricity industry restructuring. According to Paul Joskow (1999)"Transmission investment decisions cannot rely exclusively on market mechanisms. They are lumpy, involve externalities, and are characterized by economies of scale. Restructuring experience to date shows no evidence that market forces will draw significant entrepreneurial investment into transmission capacity." Consequently, transmission expansion requires centralized planning and investment"

6.6.37 *As noted earlier, transmission costs represent a small fraction of the overall costs of electricity, yet relatively small investments in transmission may have a major impact on economic efficiency and system reliability. Furthermore, in the context of deregulated markets, it is possible that a transmission investment that contributes little to the reduction of social costs may have a significant impact on transfers between consumers and producers due to mitigating market power. For example, a line between two self-sufficient areas may not carry much flow, but its presence creates competition in each of the local markets, thereby mitigating market power exercise and reducing prices to consumers in both markets. In this situation, consumers clearly benefit from the investment, but financing may be difficult. When control and ownership of transmission arc separated, a major challenge to investment and innovation is the creation of a financing linkage between those who benefit from the investment and those who make the investment."(Quote :National Transmission Grid Study : Issue Papers ,US Department of Energy, May,2002)*[19]

[19] http://certs.lbl.gov/ntgs/issuepapers_print.pdf

7. Proposed formulation for connectivity and Long Term Access

i. The Connectivity Regulations issued in 2009 were based on the principle that affordable power should be made available and from transmission side benign regulations are provided to enable all generators to connect to the transmission grid and infrastructure is created for transferring the power from generation rich areas in the country to demand areas. While through the product of "Connectivity" an assured entry access to market was provided, through a bunch of access like Long Term, Medium term and short term, sufficient flexibility was provided to Generators . Also level of bank guarantees at different levels was kept low. This was done with the basic premise that there would be an environment of mutual trust between Generator and transmission planner. It was expected that Generator would keep the transmission planner fully apprised about its progress including statutory clearance and meanwhile would make best possible efforts to find customers so that last mile connectivity can be provided well within time. To implement these Regulations were formulated and Regulatory approval was given for major investment in transmission. In this system the cost and risk allocation was tilted more towards transmission as compared to generation.

ii. All aspects of transmission planning, implementation and transmission cost allocations need to handled in a comprehensive manner; and this may require an overall change in the way the transmission system is planned and implemented in the country. While the cost and risk allocation need to be changed and this change is required to capture the uncertainty and sufficient safeguard need to built in to take care of execution uncertainties in generation projects in respect of statutory clearances , delay in fuel tie up etc. .

iii. The proposed change in risk allocation may appear negative to Generators , but it must be recognized that cost, risk and benefits need to be allocated proportionally and risk cannot be transferred to existing customers like state utilities. It must be understood by the generators that to create a conducive environment for transmission investment, which provide them access to market it is necessary that both generator and demand customers need to be brought on board.

iv. While the coal allocation process in the country is linked with certain milestones like clearances and PPA, in transmission system it is not intended to follow similar strict milestones. The generating on projects as well as transmission projects involve a large time frame and due to block nature of transmission investment wherein it may not be possible to under scale the transmission project after commencement of its execution. In the proposed mechanism a timeline of bank guarantees is proposed to be align with the progress of generating stations and tendering process of transmission projects.

v. The proposal is based on international methodology for connection and access for large generators and past five years' experience in India. Some of the proposals may need modification for providing connectivity and access to renewable energy generators to support public policy. Comments of stakeholders are invited on this aspect as well.

7.1. ALTERNATIVE 1

7.1.1. If present methodology of **initially attributing transmission expansion to Generator and shifting it later to beneficiaries is continued** then following alternative approaches which can form the basis of fixing liability of generator for transmission system can be proposed:

7.1.2. Choice of product will be given to applicant. In accordance with his choice he will get transmission service and construction bank guarantee to be furnished by applicant would be equivalent for capital investment to be made in transmission system. In case no transmission system augmentation is required then Bank Guarantee corresponding to seven year zonal transmission charges needs to be submitted to avoid unnecessary holding of access. Three type of products are proposed to be offered:

7.1.3. **TYPE A. Connectivity plus Full Network Access**

Generator to pay advance in form of sufficient(100%) bank guarantee for cost of Transmission system both for Connectivity (Shallow connection) and Network expansion.(deep Connection)- These guarantees are to be given in stages and just before the execution is to be started for transmission system. Outcome will be assured evacuation and assured evacuation to both target region and point to point as transmission system shall be planned for anticipated scenario for all regions.

I. Exit before Commissioning: No charge, recovery through bank guarantee, adjustment in case of alternative user.
II. Exit after Commissioning: Adjustment from retained bank guarantee.
III. After Commissioning bank guarantees to be returned in proportion of firm PPA and in case of no PPA bank guarantee proportional to NPV of 12 year transmission charges for newly constructed transmission system will be retained.

7.1.4. **TYPE B: Connectivity Access:** Planning of transmission system on the basis of future load generation projection and Generator to pay in advance only for connectivity line(Shallow Connection) and Transmission work for connectivity line will be started only if generator achieves critical milestones like order for main Plant and all important approvals for fuel tie up and environmental clearance.-Outcome will be only assured connectivity to the grid . No assurance of target region or point to point evacuation

7.1.5. **TYPE C :Connectivity plus Injection Access:** A mix of both wherein Generator to pay in advance for connectivity line and 50% of the cost of Network expansion. Transmission work will be started only if generator achieves all critical milestones like order for main Plant and important approvals for fuel tie-up and environmental clearance. Outcome will be only assured connectivity to the grid. Assured evacuation to target region but no assurance of point to point evacuation. Bank Guarantee for Connectivity portion and Access portion are to be treated separately.

7.1.6. Summary of these options is given in following table:

Type	**Network**	**BG**	**Facility**	**Exit**	**Transmission Charges**
A	Connectivity plus network Access	Connectivity line(non-refundable plus network Access- Adjustable BG	Full Access	12 year NPV of transmission tariff for new assets	Usage based

B	Connectivity	For full cost of Connectivity Line(n-refundable)	Only assured connectivity	Bank Guarantee will not be refunded	Fixed Monthly tariff for connectivity line plus 25% of Average Access charge for installed capacity (Adjustable against STOA.
C.	Connectivity plus injection	Connectivity(non - refundable plus 50% of network- Adjustable BG)	Only target Region access	12 year NPV of transmission tariff for new assets	Usage based
	^ For construction of connectivity portion cash advance will be taken while for Access portion bank Guarantee may be taken. ^^ The bank guarantee shall be initially valid for 5 years .It should be issued by Bank / Financial institution approved by CTU.				

Table 7: Alternative 1 -Connectivity and Access Options

7.1.7. Under category C, while deciding priority for Short Term Open Access generator would be given preference over other short term customers in case margins are existing or found in the target region .

7.1.8. The option C is a option based on **handshaking concept**. It is expected that while generator will be given access based on target region, from drawal entities requirement of access will come slightly later and at regional boundaries, it will meet if planning of ISTS is done in a collaborative way.

7.1.9. However in case of new pooling point type of access for all generator , proposed to be connected at that pooling point shall be of similar type. In case generator chose different type of access , it is proposed to give preference of allocation in order of A, C and B .

7.1.10. An important point is that in treatment all these cases capacity corresponding to installed capacity plus overload capacity shall be considered for access i.e no part LTA concept shall be applicable.

7.1.11. The connectivity option given under option B is a temporary arrangement . It is to be given initially to facilitate generation station connectivity to the grid. It should not be considered as permanent feature because generators would have to face congestion in that case and it should make efforts to shift to another option as project progresses toward commissioning. Trying to depend on connectivity and short term open access would result in problem in system operation. System operator in this situation had full authority to deny access to such entities.

7.1.12. Charging generation stations for connectivity portion is not to be considered as discrimination with CPSU generation stations because liability of payment is only in case when generator has no identified beneficiary (ies). Once generating station has beneficiary, its payment liability gets shift to beneficiaries as in case of CPSU projects.

7.1.13. **Bank Guarantees:**

7.1.13.1. These bank guarantees would be adjusted after Commissioning of both transmission assets and generating assets against 12 year NPV of transmission charges of these assets depending upon the firm PPA . In case generator has PPA corresponding to full capacity, entire amount of bank guarantee would be returned i.e there would be no need to extend Bank Guarantee.

7.1.13.2. In case generator is not having beneficiary(s) after commissioning of its plant then the bank guarantee would not be returned and it need to be extended for an amount equivalent to 12 year NPV of transmission tariff for the assets created due to LTA application of generator**.**

7.1.13.3. Every year the amount of bank guarantee would get reduced corresponding to balance period i.e after 3 year it will be taken corresponding to 9 years NPV(12-3 years**).**

7.1.13.4. Also in case of pooling stations the responsibility of generator for bank guarantee shall be proportional to its capacity. For example in case a pooling station and other transmission asset is being created for 5000 MW then a generator of 1000 MW capacity shall furnish BG to the extent of 20% .

7.1.13.5. This is being proposed to enable connectivity and access to Renewable generators so that all the cost of transmission infrastructure created in a renewable potential area is not borne by first mover .

7.1.13.6. Sample Calculation of BG for construction of Connectivity line for a 500 MW Generating station is given below:

1. 400 kV D/C Transmission line of 50 km (Rs.135 lakh per km)= 6750 Lakhs
2. Two bays at Pooling station= 1200 Lakhs
3. Miscellaneous ,Cost escalation etc =1050 lakhs

Total Capital cost = 100 Crs.

For this sample case first year tariff work out to be Rs 19.22 Cr .

The NPV computed of this tariff stream for 12 years @9.5% = Rs 120.59 Cr

7.1.13.7. The proposed mechanism of bank guarantees would protect the other consumers form bearing the cost of stranded assets. Transmission licensee tariff shall be shared by all DICs after adjusting the amount recovered through Bank guarantee.

7.1.13.8. A proposed timeline of various activities is enclosed as **Annexure-XIX** to explain the various milestones in granting LTA. The timeline of submission and quantum of bank guarantee may depend on risk perception in generation project commissioning. If a particular generator is not sure about its project, it can opt out of the process well before the award of work of contract for transmission system.

Treatment of delay in commissioning, Change of Region and Exit under Alternative 1

7.2. Issue of delay in Commissioning:

7.2.1. To provide equal treatment to generation projects implemented by CPSUs and IPPs, it is proposed that after a grace period of three month during which Generator shall be responsible for IDC liability , staggered payment system for 25% , 50 % and 100% transmission charge shall be applied for deep connection(network expansion) for delay of each quarter. For the connectivity portion no grace period shall be allowed as it may be utilised by generator for drawal of startup power and injection of infirm power of this shall be applicable only in case of transmission projects implemented under cost plus system. For competitively bid projects no relaxation shall be allowed in case of delay in commissioning of generation project

7.2.2. The rationale for this proposal is that at present transmission license in case of delay in its transmission project is only compensating generator to a small extent and not compensating for generation loss. So in this situation insisting on a firm date from generator, which may get delayed due to certain force majeure, may not be appropriate. However this relaxation is not proposed to be allowed in case delay is due to any technical and commercial issue between generators and its contractor or customers.

7.2.3. In case of delay in commissioning of generating station, transmission tariff for all the assets developed shall be payable by the Generator in accordance with Option A, B or C chosen by the applicant .These asset shall form of part of pool only after commissioning of the Generator. In case assets are constructed for multiple units then transmission charges corresponding to commissioned capacity shall become part of pool and balance shall be payable by applicant himself. For example if access was sought for 1000 MW (2x500 MW)capacity and transmission assets capital cost is 1000 crs and it tariff is say 190 crs then after commissioning of first 500 MW unit , transmission tariff of 95 crs shall become part of pool and 95 crs shall be payable by generator himself. For the pooled transmission tariff generator shall be liable in accordance with the sharing Regulation wherein transmission charges in accordance with Usage shall be payable.

7.2.4. Change in Target Region : As change of Target region would be applicable for only type C, it would be allowed without any payment but there shall not be any guarantee of access if change of region is informed after commencement of execution of transmission system begins. Also for this a fresh application would required to be submitted and priority shall be considered with new date of application.

7.3. RELINQUISHMENT OR EXIT

7.3.1. Detailed discussion and survey of international practices for connection of large generator was examined to formulate this.

It is proposed that there shall be no concept **of 'Stranded Capacity' in** case of 'Exit' option. In an ISTS, where planning of transmission system is done based on existing Access and future planned Access, CTU is reporting that finding Stranded Capacity is proving to be difficult and finding impact of particular access on economics of power market by holding the Access, although important, but is also proving to be difficult to quantify.

7.3.1.1. A prudent decision needs to be taken by the Generator regarding timing of exit. During inception stage of transmission system, 'Exit' may be permissible but once it is posed for bidding, it shall not be allowed as it affects other stakeholders . It is proposed that if generating station is not commissioned at all, it shall bear NPV of transmission charges of new assets for 12 years depending upon type of access A, B or C it sought.

7.3.1.2. Before starting the competitive bidding process or tendering activities for planned transmission system, confirmation from Generators and demand customers shall be sought again and if required transmission plan shall be modified if required.

7.3.1.3. The relinquishment or EXIT charges shall be according to each type of access and shall be adjusted from Bank guarantee.

Type A: Bank Guarantee shall be submitted towards total transmission capital cost . In case EXIT is sought before commissioning of Generating station and it is after placement of award for construction of transmission project in case cost plus and after bid opening of competitive bidding, bank guarantee shall not be returned and If EXIT is after commissioning of generating plant due to any subsequent reason, the Bank guarantee shall be returned after adjusting NPV for transmission charges for 12 years but for connectivity part adjustment or no refund shall be given.

Type B: Same as above but as BG is given for connectivity part; no refund shall be given after placement of award.

Type C: Same as A

7.3.1.4. In this regard, it was enquired by few stakeholders that if a generator. is not opting for 'Exit' and still holds its Connectivity and LTA (or GNA), how transmission charges shall be recovered from him, if transmission charges are levied based on actual usage.

7.3.1.5. The transmission access cannot be left at the discretion of generator. If it is not using the transmission system (ISTS) due to any reason like fuel shortage, etc., for two quarters consecutively, it is proposed that it shall be considered as 'Exit' and applicable charges shall be levied by revoking bank guarantee for balance period.. An option would be given to the generator that if he wants to hold on the access, it will keep on paying long term transmission charges corresponding to injection and withdrawal Access, depending upon type of access, at the rate of average transmission charges. However the transmission capacity can be used in short term by other users at same pooling point and corresponding adjustment shall be given to this generator.

7.4. ALTERNATIVE 2

7.4.1. Under Alternative 2 transmission planning execution and transmission cost allocation shall be based on GNA concept as proposed by CEA and CTU. There shall be no optional arrangement under this alternative. Whenever a Generator or Drawal customer wants to connectivity and access to ISTS , it will declare its GNA (General Network Access) Requirement. For Generator it shall correspond to its Net Installed Capacity (ie. Installed capacity – Auxiliary consumption). IT shall also consider its overload capacity and that shall be considered as its GNA. Declaration of target region shall be optional and if Generator have no identified beneficiary , CTU shall plan system in accordance with load generation forecast.

7.4.2. In this system there is a possibility of developing over capacity in ISTS.

7.4.3. In the proposed GNA mechanism it is stated 100 % evacuation irrespective of target region shall be assured.

7.4.4. Transmission system shall be planned based on GNA requirement of Generator and demand customer.

7.4.5. Both generator and demand customers shall submit bank guarantees corresponding to their GNA. To handle the scenario when drawl GNA is less than Injection GNA then either planned transmission system would be developed in accordance with drawal GNA. In this situation option would be given to Generators to bear both injection and withdrawal GNA responsibility for differential i.e for an application period if additional (new) demand GNA requirement is say 7000 MW and application for injection GNA is 10000 MW then Generator may be asked to bear GNA responsibility of both injection and withdrawal for 3000 MW in addition to 7000 MW injection GNA.

7.4.6. Before starting the competitive bidding process or tendering activities for planned transmission system, confirmation from Generators and demand customers shall again be sought and transmission plan shall be modified if required.

7.4.7. Before commencement of execution of transmission system, a status check of progress of statutory clearances like land, fuel, water and environment clearance shall be checked .In case it is found to deficient to a large extent, the executing agency for transmission system may approach Commission for guidance.

7.4.8. Concurrence for implementation of transmission system of generators and Drawal customers shall be sought again if any clearance is not received. This will be done before placement of order in cost plus system and before opening of bids in case of competitively bid projects.

7.4.9. It shall be agreed by the transmission customer(s) on whose request the transmission system is being developed that non unavailability of fuel and clearances shall not be considered as force majeure event and they shall pay transmission charges for the system as per prevailing Regulations.

7.4.10. Treatment of delay in commissioning, of Generating Units/Project, Change of Region and Exit under Alternative 2

7.4.10.1. Delay in Commissioning:

No relaxation for delay in commissioning of generation shall be allowed if transmission is being built through competitively bid project. If the system is being developed through cost plus system, the transmission licensee and user of transmission system shall ensure through a bilateral agreement that any burden on account of delay is not transferred to other DICs. In case of delay of generator, generator shall be responsible and in case of delay in downstream transmission system, drawee customer shall be responsible for payment of transmission charges for the period of delay.

7.4.10.2. Change of Region:

No charge shall be applicable for change in region, while it will be assured that there will be no congestion in injection region for generator and drawal region in case GNA was sought by drawee , however point to point access shall not be assured.

7.4.10.3. Exit or relinquishment charges:

If exit is sought before commissioning of Generator (GNA seeking entity) , bank guarantees shall be revoked in case generator is not able to find alternative equivalent user in same time frame at same pooling station. In case alternative users emerge after a gap, adjustment amount shall be refunded back.

7.4.10.4. In case of drawee customers, if demand is not realized or not come up, transmission charges shall be adjusted from bank guarantee and computation of transmission charges shall be done on the basis of average transmission charges in the country. For example GNA was sought by a drawee customer for 1000 MW and demand is only 600 MW, transmission charge of recovery for 600 MW based on actual usage and for 400 MW it shall be based on average transmission charges computed for the country.

7.5. Transmission Cost Allocation

7.5.1. As at present the decision of Generator to seek LTA is affected by the twin fact of uncertainty of beneficiaries and present mechanism of billing of transmission charges based on LTA. While being in agreement with the concept of GNA for transmission planning, it is proposed to deviate from the concept of GNA proposed by CEA and CTU in so far as the payment of transmission charges is concerned. If payment liability based on LTA or GNA is adopted, it will further dampen the true declaration of injection and withdrawal from ISTS and will hamper transmission planning process. Again generators citing lack of PPAs will shy from declaring their GNA requirement till last moment and the process of transmission planning, project execution will suffer and in case of mismatch, congestion will arise again. Once it has been decided that in pursuance of National Electricity Policy, the transmission charge allocation shall be based on Distance, Direction and Usage , it is not correct to saddle the beneficiary either generator or drawee entity with transmission charge liability based on pre-determined contract. Also as National Electricity Policy mandated that transmission system can be built without prior agreement, it is not prudent to wait for generator or drawee to enter agreement and face the consequence in form of congestion. The present system of point to point LTA is a discouragement for generator as it binds him to a consumer or a target region. In a changing market scenario, concept of Approved Injection and Approved Withdrawal already in vogue in PoC mechanism appears to be a better mechanism for capturing usage. The transmission charges need to be paid on Approved injection and withdrawal for the particular application period based on forecasted injection or withdrawal.

7.5.2. Third draft amendment of Sharing Regulation, based on this philosophy was proposed in February , 2014 and after receiving the public comments , public hearing was held on 12.6.2014. The same is under finalization in the Commission.

7.5.3. Based on stakeholders' comments on this staff paper, draft amendments in Connectivity Regulation would be proposed. After following due consultation process again, if any other subsequent change would be required in Sharing Regulations due to proposed charges for connectivity , it will be proposed later.

8. PROPOSED TRANSMISSION CAPACITY ALLOCATION MECHANISM FOR POWER MARKET- COLLECTIVE TRANSACTIONS

8.1. In accordance with prevailing Regulations (Short Term Open Access In Inter State Transmission System), the users under collective transaction get the corridor for day ahead transaction at the last and were facing problem of congestion. This is perhaps resulting in stagnation of growth of power market as participants are not sure that after bidding, whether they will get power or not. One possible **solution is to reserve some capacity for collective** transactions, but it was not considered to be an optimal solution, as in the event of non utilization, the reserved transmission capacity cannot be used by other participants. Also there are problems in reserving capacity like who will pay for it and how its cost will be shared.

8.2. It is proposed that to give equal treatment in allocation of transmission corridor and bring "equity" among bilateral and Collective transactions, a new system of participation of buyers and sellers in Power Exchanges in e-bidding of transmission corridor is proposed. This will require amendments in CERC Short Term Open Access Regulations.

8.3. A window for collective participants, giving equity with bilateral participants, is proposed for transmission corridor booking under short-term market. Collective participants would be allowed to participate in booking Transmission Capacity in STOA 'Advance' and 'FCFS' categories, as outlined in Table-1 below. Such collective participants would use the pre-booked transmission capacity of a particular corridor to participate in Power Exchange Day Ahead Market (DAM) and get scheduled based on the corridor already reserved by the participant.

8.4. Frequent congestion in corridor (e.g. ER-SR & WR-SR) in Short Term Market is making bilateral participants to book corridor in Medium Term Open Access (MTOA). Tendency of the participants to reserve transmission capacity for period just more than 3 months (Eg. 3 months and 1 day etc.) is required to be curbed. Therefore, it would be rational to include Transmission Open Access up to 1 year under Advance STOA and limiting MTOA from 1 year to 3 years, in line with CERC Power Market Regulations, 2012.

Table 8: Present Open Access Reservation Mechanism for Transmission and Proposed Changes

Priority in Transmission Capacity Allocation (decreasing from top to bottom)		Application Window Open	Delivery Duration	Capacity Allocation mechanism
LTOA (B[20])		~4.5 years ahead of delivery start	12 to 25 years	FCFS[21], with all the applications in a month considered together.
MTOA (B)		5 months ahead of delivery start	3 months to 3 years	FCFS, with all the applications in a month considered together, according priority to applications for longer delivery period.
STOA	ADVANCE (B *+C*[22])	Upto 'L[23]', for Month 3[24] Upto 'L-5', for Month 2 Upto 'L-10', for Month 1	Upto 3 months ahead	All applications by bilateral transaction participants, up to gate closure considered together. Congestion handled by e-bidding (explicit auction). (Collective transaction participants would also be allowed to participate in this segment considering Exchange as their counterpart, while individual participant would choose and apply for a particular corridor which will best suit their requirement.)*
	FCFS (B *+C*)	4 days ahead	delivery upto a calendar month	All applications up to gate closure considered together. Congestion handled by pro-rata scheduling.
	Day Ahead (C)	15:00 hrs on D[25]-1	1 day	Congestion handled through implicit auctioning. Participants with Advance Booking of Transmission Capacity to be considered in upstream of the transmission corridor pre-booked for the purpose of implicit auction.
	Day Ahead (B)	15:00 hrs on D-1	1 day	All applications upto gate closure considered together. Congestion handled by pro-rata scheduling.

[20] B - Bilateral
[21] First Come First Serve
[22] C - Collective
[23] L – Last Day of current month
[24] E.g. for delivery in the month of August, application should be made in May (Month 3)
[25] Delivery Date

	Contingency (B)	From 15:00 on D-1 upto 1.5 hrs before delivery	1 day ahead of delivery & intra-day	FCFS, Congestion handled by pro-rata scheduling.

* Proposed changes are Underlined.

8.5. Collective (PX) participants who have successfully participated in pre-booking transmission capacity in STOA Advance or FCFS categories could benefit by being cleared in DAM Auction at prices of Downstream (Buyer) or Upstream (Seller), in spite of congestion in respective corridor. Participants with pre-booked corridor will be treated as 'Priority Portfolio' for bidding in Downstream(for Buyer) or Upstream (for Seller), hereafter called Guest Region, w.r.t. the transmission capacity pre-booked, while the same participant will also be allowed to participate as 'Normal Portfolio' for bidding in his Home Region. Normal Portfolio is one with no corridor in Advance/FCFS and relying on corridor available on Day-Ahead basis (like the current portfolios in the system). Selected bids of Priority Portfolios in PX DAM would be cleared at prices of Guest Region, thereby avoiding the burden of higher prices of congested Downstream Region.

8.6. Pros & Cons of the Proposal

Pros:

Proposed mechanism would benefit the Short Term Market participants significantly by giving 'equity' to Collective participants with Bilateral participants, thereby reducing the price burden of Congestion borne largely by participants in collective transaction (Power Exchange participants).

Currently the transmission capacity allocation rules favour bilateral transactions. Proposed changes would bring changes in the transmission capacity allocation.

Competitive pricing of transmission capacity, at times of congestion, would be more real with increase in participants in Advance & FCFS categories paving way for a uniform competitive market for transmission capacity.

The proposed mechanism would unbundle the 'Energy +Transmission Congestion Price' for Power Exchange participants who have booked transmission corridor in advance.

Even smaller participants would be able to book the transmission corridor in advance which will remove barrier of non-availability of transmission capacity for meeting their requirement.

The proposal can be implemented with minimal regulatory and procedural changes in Open Access.

Cons:

With increase in number of participants in the transmission capacity allocation process (particularly e-bidding), there would be need to automate entire process to handle large number of applications.

In case capacity booked for Exchange transaction is not utilized by the participants, he would not get back cost paid for such booked capacity. Thus the participant would be taking risk of transmission capacity booking.

Another related issue would be how to redistribute such unutilized capacity. It is proposed that such unutilized capacity may again be re-distributed amongst the Exchanges as per the existing methodology of transmission capacity distribution between Exchanges. This may, although, lead to one more iteration of exchange of information between Power Exchanges and NLDC.

9. UTILIZATION OF TRANSMISSION CHARGES COLLECTED THROUGH E-BIDDING AND CONGESTION REVENUE

9.1. The congestion is an important indication for transmission expansion. With detailed analysis , it can be found that congestion being experienced in a particular zone is a result of very short term load generation balance issue or it is due to infrastructure bottleneck which needs to be addressed through transmission expansion.

9.2. In some of the countries, the congestion rent is used as one part of transmission charges, and once this congestion rent is increased beyond a point , the transmission company is asked to build new line.

9.3. At present the total revenue requirement of inter-state transmission licensees is recovered through transmission charges. While to avoid uncertainty in transmission charge recovery, congestion charge is not part of transmission charges, the amount collected through e-bidding and congestion revenue is collected and routed to a PSDF. From PSDF , the procedure to withdraw money for interstate transmission system is complex . Also past experience of using short term transmission charges for development of new transmission system was not encouraging as transmission licensee did not want to dilute their return on equity by part financing the transmission expansion through short term open access charges.

9.4. It is proposed that any amount received through e-bidding and congestion revenue be adjusted towards transmission charges to be paid by all DICs on quarterly basis. The market participants may raise the issue that it should be returned to them on one to one basis, but if it is done, it will distort the signal which is intended to be captured through congestion. As all DICs who are long term customers of the transmission system will get back some money, the acceptance for future transmission projects will be easier.

9.5. However, to address the issue of congestion, it is necessary that investments to mitigate congestion is done with some fast track projects. The CTU shall submit monthly detail of these charges with detail of corridors. Based on this data , Commission, in consultation with System operator will advise CEA/CTU to plan such system on priority basis and implement it through the mechanism of competitive bidding wherein compressed implementation schedule is given as pre-condition.

10. SUMMARY

In view of the above discussion following actions are proposed to be taken:

10.1. Amendments in Chapter 3 of IEGC (Grid Code) – Planning code for Inter State Transmission System.-

10.1.1. Planning based on Installed Capacity.

10.1.2. Five year rolling Transmission planning with Regulatory Compliance in regard to submission of information by STUs.

10.1.3. Transmission planning validation process

10.2. Amendments in Connectivity Regulations with respect to

10.2.1. Adoption of Alternative 1 or Alternative 2 GNA concept proposed by CEA both for generator (installed capacity)and drawee entities for planning , connectivity and exit

10.2.2. Regulation 8: Grant of Connectivity

10.2.3. Regulation 12(6)- Construction bank Guarantee Exit option – No concept of Stranded capacity ,

10.2.3.1. In case EXIT is before the transmission scheme is posed for competitive bidding , then modification in transmission scheme and relief to Generator

10.3. Amendments in CERC Short Term Open Access Regulation

Participation of Power Exchange in Transmission corridor allocation through e-bidding.

10.4. Amendments in related regulations for using congestion charges, congestion revenue, e-bidding amount for reducing long term charges of transmission.

11. STAKEHOLDERS COMMENTS

While stakeholders may give their views in general on all issues in this staff paper on transmission, they are also requested to give their specific comments on critical decision points, For this purpose stakeholders are requested to reply following questionnaire:

Question No. 1:

Whether Connectivity should be retained as a separate product :

(A) Yes (B) No

Question No. 2(a)

If Yes, what are in your opinion are the advantages of Connectivity as a separate product ?

Question No. 2(b)

If connectivity is retained as a separate product , then what whether is should be free or transmission charges should be borne by generator or drawee entity which is applying for connectivity ?

Question No. 2(c)

Whether for connectivity, only transmission charges corresponding to connectivity transmission system should be charged or some part of Grid transmission charges(25% as proposed) should also be charged ?

Question No. 3:

If no , what is in your opinion are the dis- advantages of Connectivity as a separate product?

Question No. 4: Bank Guarantee

What should be amount of sufficient construction bank guarantee to safe guard against the risk of stranded asset in case generating project fails to get commissioned?

(a) Is existing construction bank guarantee amount(Rs 5 lakh per MW) sufficient when transmission cost is about Rs 1 cr per MW.?

(b) Is proposed bank guarantees equivalent to cost of transmission line is sufficient?

(c) Is proposed bank guarantees are very high?

Question No. 5: Bank Guarantee

What should be amount of sufficient construction bank guarantee to safe guard against the risk of stranded asset or transfer of liability to other consumer in case generating project wants to exit/ downscale LTA after commissioning (Please give justification for your views)

(a) NPV equivalent to 12 year transmission charges
(b) NPV equivalent to 7 year transmission charges
(c) X Rs per MW of installed capacity –One time charge
(d) Five years Average Injection and withdrawal charges
(e) Five years Average injection charges only

Question No. 6: Delay in Commissioning

In case of delay in generating unit(s) /project:

(a) Date of LTA should be firm and no relaxation should be provided
(b) If information of delay is provided sufficiently in advance some staggered relief can be granted
(c) Issue should be decided mutually between generating company and transmission licensee subject to condition that no burden is transferred to other users

Question No. 7: Shallow Connection vs Deep Connection:

(a) what is your view on shallow connection vs deep connection
(b) Shallow connection should be permitted to only Renewable generation or to both Renewable and conventional generators.
(c) Under shallow connection system how transmission planning will be done and who shall bear the Grid level transmission charges

Question No. 8:

a. Whether you are a injecting entity or Drawee entity or both?

Question No. 9: GNA

a. What is your opinion on General Network Access (GNA) proposed by CEA ?

b. Whether it should be adopted for transmission access and transmission charges ?

c. What should be bank guarantees and Exit Charges under GNA mechanism?

d. Whether it would be possible to plan transmission system to give assured access in all directions?

Question No. 10: Transmission Planning:

a. How Transmission planning in the country needs to be reviewed under present condition to take care of future need of robust transmission system?

b. Whether there is need for a separate Regulation for transmission planning to make it more participative?

c. Whether transmission planning should mandatorily make margins available for short term power market?

d. Whether transmission system planned by CEA /CTU need to be adequately explained from cost benefit point of view?

e. Is there requirement of making submission of information related to transmission planning legally binding?

Question No. 11 : Utilization of Congestion charges

a. Whether proposal of using congestion charges to reduce the long term ISTS transmission charges acceptable ?Or
b. Whether Congestion charges are to be utilized for creation of specific transmission assets for relieving the congestion? How should this be treated- as equity, loan or grant?

Question No.12:

Transmission corridor allocation for Power market:

a. Whether participants of Power exchanges should be allowed to participate in e-bidding for transmission corridor? or
b. For power market development, certain quantum of corridor may be reserved for power market with all participant of Power Exchange sharing the transmission charges of reserved corridor .