FORMULATING PRICING METHODOLOGY FOR INTER-STATE TRANSMISSION IN INDIA

APPROACH PAPER

CENTRAL ELECTRICITY REGULATORY COMMISSION

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GLOSSARY

AP	Average Participation Method
ARR	Aggregate Revenue Requirement
ATS	Associated Transmission System
BBMB	Bhakra Beas Management Board
BPTA	Bulk Power Transmission Agreement
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CGS	Central Generating Station
CTU	Central Transmission Utility
CUSA	Connection and Use of System Agreement
IPTC	Independent Power Transmission Company
ISGS	Inter-State Generating Stations
ISTS	Inter-State Transmission System
kV	Kilo-Volts
Kw	Kilo-watt
Kwh	Kilo-watt hour
LMP	Locational Marginal Price
MP	Marginal Participation Method
MW	Mega-watt
NLDC	National Load Despatch Centre
NHPC	National Hydroelectric Power Corporation or NHPC Ltd.
NTPC	National Thermal Power Corporation or NTPC Ltd.
PGCIL	Powergrid Corporation of India Ltd.
Px	Power Exchange
RLDC	Regional Load Despatch Centre
RPC	Regional Power Committee
SLDC	State Load Despatch Centre
UI	Unscheduled Interchange

I EXECUTIVE SUMMARY

The purpose of this paper is to propose a transmission pricing mechanism for Inter-State Transmission System in India.

This paper focuses on "allocation" of the Aggregate Revenue Requirement (ARR) of the providers of the Inter-State Transmission System amongst various network users. The determination of the ARR of the Central Transmission Utility and inter-state transmission lines is not the objective of this paper and the same shall continue to be determined as per the terms and conditions of tariff of the CERC as notified from time to time.

The present mechanism of allocation of transmission charges amongst various network users is based on a regional postage stamp method. The postage stamp method has served its purpose well till now. However, with large inter-state and inter-regional flows due to open access and trading of electricity, the flow patterns across the country have changed. 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 pancaking 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.

Three pricing approaches were considered appropriate for further investigation - (i) Marginal Participation Method, (ii) Average participation Method and (iii) Zone-to-Zone method. All three methods are based on load flow studies indicating the use of the system, but use different approaches for determining the use of the network by various users of the transmission system. Transmission charges determined using Marginal Participation (MP) Method was found to have better economic and technical properties as compared to other methods. Specific characteristics of MP, which distinguish it from others, are:

- Transmission prices determined using MP method measure how much each agent is benefiting from the existence of various network facilities.

- MP method directly computes the relative use of each network branch by generators and demand customers (The split of transmission charges between generators and demand customers needs to be specified by the user in other models). This provides clear locational signals to generation and demand customers.

- The MP method considers the meshed network as a common use facility. Utilization of the network branches as determined in MP method is based on actual power flows on the network. This obviates the need for arbitrary assumptions.

Transmission charges determined using MP method are Point Tariffs, thereby indicating that each user of the network, viz., generator / demand customer will be required to pay a fixed charge depending on its location in the network. These charges are in Rs/MW/month depending on the location of generator / demand customer and provide clear signals based on distance and direction.

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 Tariffs – such as those determined using MP 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 pre-requisite 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 transmission tariffs so determined do not lead to pancaking and hence send cost-reflective signals for efficient inter-state and inter-regional trading. The proposed mechanism considerably simplifies the allocation of transmission charges between parties involved in electricity trades on the power exchange. The generators selling power on the exchange can internalize the transmission charges in their price bids, whereas the demand customers can be charged transmission charges separately based on short term access approved.

The Approach Paper presents the results of the charges for transactions within various locations of the country using the Marginal Participation Method on the power system planning data for 2011-12. As per the methodology, the charges determined separately for each generator and each demand point connected on the ISTS will be determined based on their location and in the context of the overall flows in the power system. The results (based on load flows) attribute lower charges for demand that is electrically closely located to generation sources and vice versa. Similarly generators located close to demand have a lower cost attributed to them.

While it is technically possible to implement the charges for each location in the ISTS separately, in view of the large number of such locations or nodes, a logical method of zoning of similarly placed regions that are physically and electrically contiguous would aid the process of implementation. Accordingly, the country has been divided into various price zones, aggregating the nodes in a contiguous region. For this purpose in certain instances where the electrical system characteristics warrant, large States have been split into multiple price zones Also, in a given State, the generation and demand zoning could be different based on the electrical characteristics of the system in order to send appropriate price signals.

The Approach Paper recognises that the Indian power system is evolving and future charges cannot be determined precisely at this time. Accordingly, the thrust of the Paper is to outline the methodology, provide adequate indication of the nature of charges that would be incident on various users, and define the implementation process. In practice, based on the principles finalised, revisions to the charges would be made on a periodic basis (typically twice a year), based on the prevailing network topology.

The proposed method will thus address the key mandates of the policy and the contemporary needs of the Indian power system.

II BACKGROUND

A well developed and efficiently priced transmission system is crucial for efficient development of the power sector. The transmission system must be developed in time for new generation capacity to come on stream as well as for demand to connect to the system in a timely manner. The transmission system is also the backbone for development of efficient competitive power markets. 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.

Access to and pricing of the existing transmission system has been governed on the basis of development of the transmission network in India. Inter-state transmission originally developed at the regional level with the objective of generation evacuation from Inter-State Generating Stations. The Associated Transmission System (ATS) thus developed primarily catered to the needs of these stations and their beneficiaries who were located in the same electrical region. Transmission charges were correspondingly determined at the regional level. Over time, as there has been an increase in periodic power surpluses and deficits, others mechanisms for pricing of regional interconnections have been evolved by the CERC. The system has thus functioned satisfactorily till date.

The need for aligning to the future requirements of a national transmission network has become apparent over a period of time. Creation of a national transmission system is a policy priority and the power system has been developing fast in that direction. There are many benefits of a national power system in terms of efficient development and utilisation of the resources in the system, robustness of the grid and deepening of the competitive power markets. 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.

This Approach Paper discusses various issues and options in this regard and presents the preferred framework for the ISTS. The Paper is organised as follows. The present chapter provides a background of the development of the ISTS network and its pricing, and articulates the need for change in the development and pricing principles. Chapter III thereafter specifies and elaborates on the available options, and identifies the preferred framework based on the selection criteria. Chapter IV elaborates on the characteristics of the selected framework. Chapter V provides an impact analysis for various system users. Chapter VI provides the details of the implementation mechanisms for the selected framework.

1. DEVELOPMENT HISTORY OF THE ISTS NETWORK AND PRICING

The Indian power system currently features more than 180 GW of generating resources, making it one of the largest integrated electricity transmission networks in the world. Of this, more than 50 GW of generation capacity is directly connected to the inter-state transmission system (ISTS). The ISTS in India is considered to be extremely robust, with the ability to withstand the wide variations in grid conditions that the system routinely faces. Electrically India is divided into five regional grids – North, East, West, South and the North-east. The regional grids came into being on account of the development of regional generating stations by the CPSUs and regional power enterprises like the BBMB. The network was primarily developed by NTPC and NHPC as associated transmission systems for the generating stations. With the formation of PGCIL in 1991, the networks of CPSUs were transferred to PGCIL for independent operations. Networks of the BBMB were developed jointly by the beneficiary states and continue to be augmented and operated by the organisation.

Over time the system capacity has been increasing significantly with deepening of the ISTS. Synchronization of four of the regions has been achieved, providing tremendous robustness to the system. On account of better management as well as the enhanced physical characteristics, grid disturbances are down to a minimum. Along with enhanced investments from incumbents, the transmission system is also attracting private capital. Powerlinks Limited, the first IPTC started its operations in 2004. The Western Region transmission system augmentation is being undertaken by Reliance Power Transmission Limited. Several IPTCs for are also being selected through competitive tenders based on the provisions of the EA 2003.

The pricing framework for the ISTS has also evolved over time. Initially, the costs of the ATS were clubbed with the CPSU generation tariffs for the respective plants. Subsequently, with the formation of PGCIL and also on account of non-plant specific system strengthening investments, the pricing framework was made independent of the generating stations, and the overall revenue requirements of PGCIL was apportioned on the basis of the energy drawn by the various constituent states.   The arrangements were subsequently changed in 2002 under the ABT arrangements wherein the transmission revenue requirements were allocated based on the MW share of the beneficiaries.

Since the move to the ABT arrangements, the CERC has been making regular refinements to the transmission pricing framework on the pricing arrangements. The box below summarises the key changes made since 2002.

Box # 1: Summary of key changes made to the ISTS pricing framework since 2002

1. MW based transmission charges introduced based on capacity allocation of beneficiaries

2. Reactive charges introduced

3. Mechanism for sharing of costs of inter-regional links rationalized

4. Charges for long term and short term open access defined

5. Bidding for transmission capacity

6. Changes made to charges for short term open access

7. Greater linkage to usage identified - Charges for ICTs identifiable to beneficiaries allocated directly to beneficiaries

8. Congestion charges introduced for UI transactions burdening the system

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As is apparent, substantial changes have been made to the pricing framework. Several of these changes have been in response to the changes in the network usage and the progressive evolution of competitive energy markets in the form of short term trading, UI transactions and trading on the Power Exchanges since mid-2008. A view of the evolution of the inter-regional transmission system in the past few years and the growth foreseen in till 2015 further illustrates the changing nature of the ISTS.

Table # 1: Inter-regional transmission links

Inter-regional links	End of 9th Plan (March 2002)	By 10th Plan (March 2007)	By 11th Plan (March 2012)	By 2014-15
ER-SR	620	3120	3620	3620
ER-NR	120	4220	11120	19420
ER-WR	360	1760	6460	12760
ER-NER	1240	1240	2840	2840
NR-WR	980	2080	4180	7180
WR-SR	1680	1680	2680	6880
NER/ER-NR/WR	-	0	6000	6000
Total	**5000**	**14100**	**37400**	**58700**

Source: CEA

The rapidly increasing inter-regional capacity has caused a change in the nature of the ISTS within a short time. From a predominantly regional system it has quickly evolved into a national transmission system. This is also the intent of policy (discussed subsequently) which emphasises the need for evolving a national transmission system to harness the natural resources optimally, evolve well deep competitive markets, and also to add robustness to the power system.

2. CURRENT ARRANGEMENTS FOR PRICING ON ISTS

The present mechanism of pricing on the ISTS follows a regional postage stamp basis. This implies that all users of a system in a region pay the same price per MW of allocated transmission capacity. The pricing framework has been working quite well and has a high degree of acceptability among the system users. Both the transmission service providers as well as the users are state owned enterprises (although the ownership is split between the federal and state governments), and in general there is a high degree of acceptance of the framework. However, in recent years, the mechanisms have come under test on account of the increasing short term transactions over the regional transmission lines and the inter-regional links. Also, with power plant capacity in one region being allocated substantially for beneficiaries in other regions, the pricing of the intra-regional and inter-regional links has been an issue. The CERC has made substantial modifications to the cost allocation principles among the beneficiaries in the last few years to accommodate the changing nature of use of the ISTS.

As mentioned, a considerable body of work has already been undertaken by the CERC. The discussion paper issued by CERC in February 2007 presented comprehensively the various issues. This was followed by an interim order in July 2007 which dealt with the issues further and made some specific awards on sharing of the transmission charges among the various beneficiaries. The concluding order in March 2008 made some improvements, but on the whole continued several of the measures earlier. Based on this the arrangements currently in place for sharing of charges of the ISTS are summarized below.

Box # Arrangements for sharing of Transmission charges for the ISTS

1. Charges for a regional transmission system are apportioned among all users of the system in proportion to their average MW demand;

2. ICTs identifiable to a beneficiary are charged exclusively to the beneficiary. However where the beneficiaries agree to pool the charges, the pre-existing system of pooling of charges is retained;

3. New ATS costs are shared by the direct beneficiaries of the project (who may be located in other regions) unless the existing regional participants agree to share the same by adding the costs in the regional pool costs. In certain cases the cost of the ATS is split in two parts – the first part being borne by beneficiaries of the generating station and the other (for system strengthening) being subsumed in the regional pool;

4. Costs of inter-regional links are borne by the beneficiary regions broadly relating to the

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nature of benefits. For example, if certain links predominantly benefit a recipient region, then the charges are borne by the recipient region. Alternatively, if there is regular reversal of flow directions, the regions involved share the charges;

5. STOA attracts a charge that is lower than the regular charges for beneficiaries on account of the "incidental" nature of the access.

3. NEED FOR CHANGE IN PRICING FRAMEWORK

The rapid changes have resulted in a perceived need for evolving the principles of operation, and in particular, the pricing principles for usage of the ISTS. The key triggers for change can be summarised as follows:

1. Change in configuration of the ISTS

2. Changing nature of use of the transmission system by various users

3. Pricing inefficiency in the emerging circumstances – the problem of pancaking

4. Evolution of open access and competitive power markets

5. Changes caused by law and policy

6. Other issues

The following sub-sections elaborate on each of these factors.

3.1. *CONFIGURATION OF THE POWER SYSTEM – CURRENT AND THE FORESEEABLE FUTURE*

The evolving nature of the grid has brought into light the changing nature of utilisation of natural resources and consequently the impact on the nature of transmission flows. An analysis of the following table along with the load flows indicates that more than 80% of the flows on the inter-regional system will be unidirectional, i.e., from generation hubs in East, Central and North-Eastern parts of the country to the predominant markets in the West and North. Even the South in the future is likely to turn out to be a net exporter with large coastal projects and nuclear power complexes coming up in the region in the 12th and 13th Plan periods. A review of the load flows by CEA confirms the above.

Table # 2: Inter-regional power transmission scenarios by 2012

Region	Requirement	Scenario
Northern	10770 MW import	Winter peak
Western	6117 MW import	Summer peak
Southern	3011 MW import	Summer peak
Eastern	18247 MW export	Winter off-peak
North-eastern	3535 MW export	Monsoon off-peak

The overall picture on power transmission is presented in the following graphic as a further illustration of the nature of flows expected.

Fig. 1: Power Transmission Networks of India

MAJOR TRANSMISSION NETWORK OF INDIA
400kV AND ABOVE
EXISTING, APPROVED AND PLANNED – UPTO 2011–12
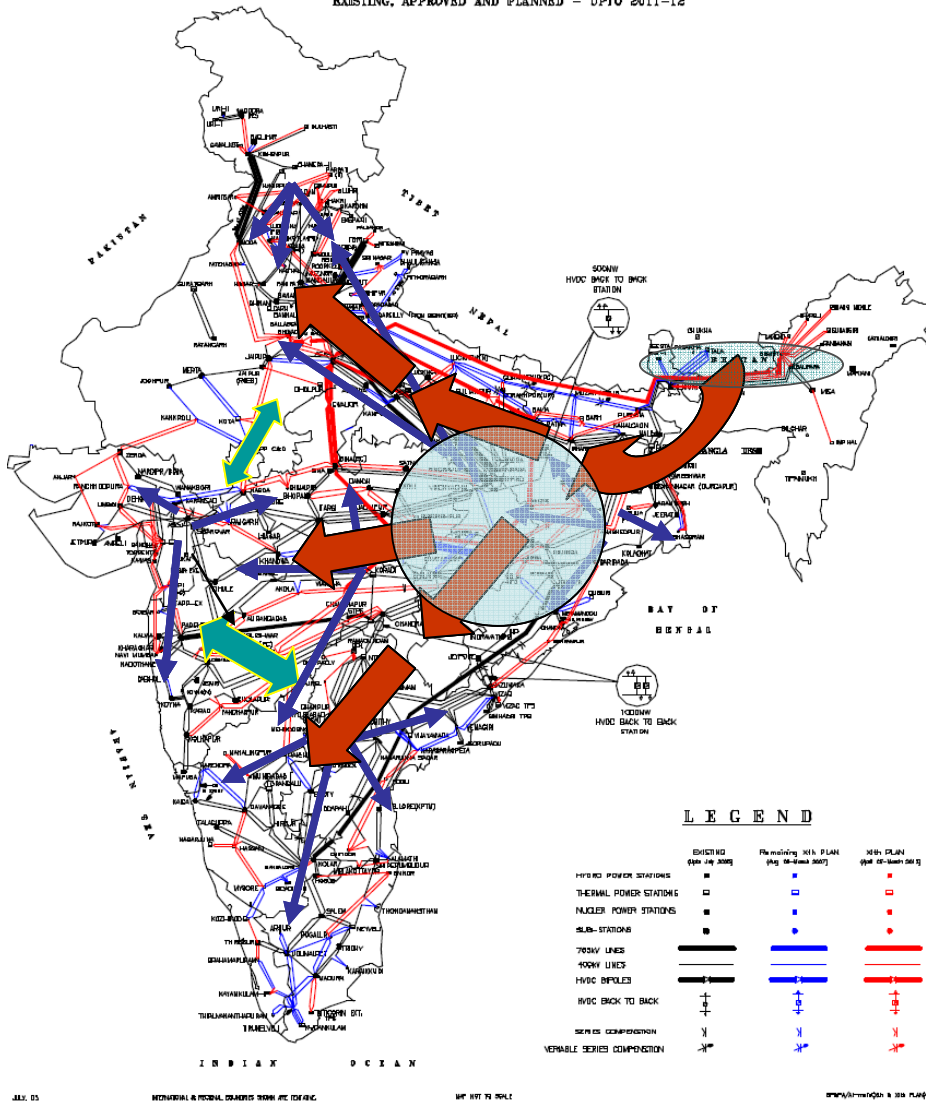
The transmission system thus features a combination of a decreasing proportion of regional flows and an increasing share of unidirectional inter-regional flows. As such, the regional boundaries are progressively getting blurred with the changing nature of the grid and increasingly the power system is being transformed into a single integrated national system. This will even more be the case once the Krishnapatnam UMPP is commissioned and the associated transmission lines carrying power to the other parts of the country become the basis for frequency integration of the Southern Region with the rest of the country.

3.2. CHANGING NATURE OF USE OF THE TRANSMISSION SYSTEM BY VARIOUS USERS

Over the last few years the nature of use has changed substantially. The EA 2003 has brought to the fore the role of the market in efficient utilisation of system resources. The resultant impact is already visible. On account of trading of power, the operating efficiencies (particularly PLF, but also SHR, Oil consumption, Auxiliary consumption parameters) have improved substantially. Equally importantly, the EA 2003 has provided an impetus to establishment of merchant power stations (mostly by the private sector, but in certain cases also by the CPSUs). The chronic shortages of electricity in the country have made establishment of these projects an apparently viable proposition.

Analysis by Mercados EMI also indicates that most of the proposed capacity is being established where it is optimal to do so from a resource utilisation perspective. In particular the Merchant thermal power stations are proposed either at the pitheads (or in reasonable proximity) or in coastal locations. Hydro power has also been encouraged by the competitive market opportunities. The capacity in question is substantial. Analysis by Mercados EMI indicates the following profile of pithead, coastal and hydro power stations proposed by the private sector:

Table # 3: Private sector capacity proposed (except Case 2 bid based projects)

Category	XIth Plan	XIIth Plan
Pithead	12500 MW	25000 MW
Coastal	8200 MW	13400 MW
Hydro	3500 MW	21500 MW

Source: Mercados EMI analysis. This is based on recently updated databases of Mercados EMI and could vary with the information available from public sources.

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.

Some relevant features of the transmission network in this regard are summarized as under:

- 220 kV and 400 kV network is tightly meshed, NER-ER-NR-WR is one synchronous grid now

- Changes in flows in one part of the network has impacts in distant network elements: Flows on Agra (UP)- Gwalior (MP) (NR-WR) line affects flows in ER

- Similarly flow of power from generation-heavy eastern parts of UP to load centers in the western parts of NR cause parallel flows on state-sector lines

- Currently, there are times when power from ER flows into NR and NER, and from WR to ER

- There are numerous such examples of externalities caused due to flows over inter-state lines

The change of character of the beneficiaries of the system also has a bearing on the pricing arrangements. In India it has been the practice that the users pay for the transmission charges on the ISTS, and not the generators. Thus the entire costs related to connection and network usage are billed by the CTU (the respective Regional Power Committee accounts) to the entities to whom the capacities are allocated.

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.

3.3. PRICING INEFFICIENCY IN THE EMERGING CIRCUMSTANCES – THE PROBLEM OF PANCAKING

The national transmission system in India is presently under development. However, given that the primary resources of power generation are unevenly dispersed in the country, the demand for regional interconnection is likely to increase. Power trading between regions is also likely to increase. In this context, it will be important to review the current pricing framework – the regional postage stamp system. A brief introduction to postage stamp method would be in place here.

The extant transmission tariffs in India are based on the postage stamp methodology. This is the simplest form of transmission pricing, where no distinction is made between the transactions with regard to the power flow path, supply or delivery points, or the time when it takes place. Therefore, a transaction between two adjacent buses could end up paying equal to that between far off locations. This method is simple to handle though without a strong economic rationale. Postage stamp rates are charged at a flat rate on a per MW basis. Mathematically, the postage stamp rates are calculated as follows:

R_t = TC * P_t/$P_{Allocated}$, where,

R_t = Transmission price for transaction t in a particular region

TC = Total transmission charges for each region

P_t = Load for transaction

$P_{Allocated}$ = MW capacity allocations in central sector power plants

The postage stamp methodology, as implemented in India has undergone certain refinements over time. The transmission costs of the Central Transmission Utility are segregated into user-specific assets and network assets. Transmission charges for 400 kV/ 220 kV step down transformers and downstream systems are payable only by the beneficiaries directly served by these assets (for assets created after 01-04-2008. The postage stamp method is applied on the upstream transmission system. Further, the transmission charges are different for long term and short term users of the grid. The charges of ancillary services such as reactive power support are user-specific. Central Electricity Regulatory Commission imposes a 5 paise/kVArh (~$1/MVArh) price on reactive power in over-voltage and under-voltage conditions. (1.03 < voltage < 0.97).

Postage stamp method is more suited when the geographical area in consideration / the electrical network is relatively small, flows are simple are do not cause large externalities (parallel flows) for intervening / electrically contiguous regions and priority is accorded to simplicity and social acceptability over economic efficiency.

The postage stamp transmission tariff is determined at a regional level in India. Inter-regional flows attract not only the transmission tariffs but also the normative losses of all the intervening regions. This is demonstrated in the figure below, where transmission tariffs for a transaction from NER to NR over the AC links have been computed. The contract path of the power from NER to NR would involve a 'contract' flow through ER. The power in NER is considered to be generated by a hydro resource at Rs. 3 / kWh. The hydro power plant is linked to the pooling station by a 400 km dedicated link, the transmission charge for which works out to approximately Rs. 0.20/kWh. Each region further attracts a transmission charge of Rs. 0.20/kWh. Electricity is assumed to be withdrawn from the grid through a dedicated link to the beneficiary in the NR. The length of the link is assumed to be 100 km and involves a transmission charge of Rs. 0.10/kWh. The total transmission charges to the load centre work out to Rs. 0.90/kWh. Similarly, the transmission losses (assumed @ 4% in each region) also get pancaked and the landed price of electrical energy at the load centre works out to approximately Rs. 4.64/kWh.

Fig. 2: Postage Stamp Transmission Tariff
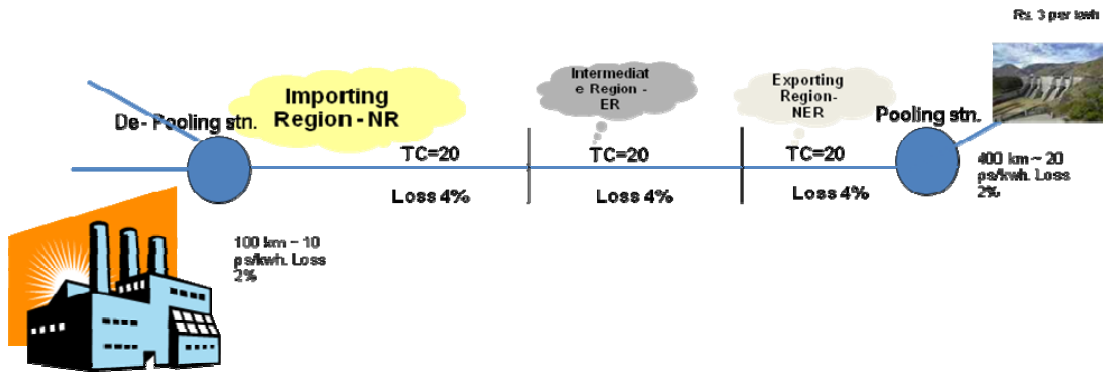
Given the high landed price of electrical energy, there is a probability that the beneficiary sets up a load centre power plant in NR, which could supply electricity at a cheaper price. The development of a load centre power plant would be justified if the charges for transmission and losses reflect the actual "utilization" of the intervening network. Therefore, pancaking of transmission charges and losses could be detrimental to trading and creation of competitive markets. Further, there is a tendency of over-estimation of losses and unfair allocation of transmission charges between existing and new users of the transmission system.

Pancaking can be viewed as a direct impact of highly meshed large networks where power generation resources are dispersed and located at large distances from load centres. There could however be large negative externalities which are not taken into account by postage stamp method. In the example above, the flow of power through the intervening regions and states could have some or all of the following impacts:

- Flow from NER to NR could lead to overloading of the power system in the intervening region and states, thereby leading to higher losses in the network, which would then be charged to the customers in the intervening states;

- The flows, especially in the future when they are expected to be largely unidirectional and heavy, could lead to higher reactive power requirement of the lines which would have to be supplied by the generators in the intervening states and this could lead them to reduce their real power output. This could reduce the availability of own-sources of generation in the intervening states to meet the state demand and increase reliance on inter-state generation resources.

3.4.   EVOLUTION OF OPEN ACCESS AND COMPETITIVE POWER MARKETS

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.

3.5. *PROVISIONS OF THE EA 2003 AND THE NATIONAL POLICIES ON PRICING OF THE ISTS AND RELATED ASPECTS*

Introduction of competitive electricity markets is a core focus of the EA 2003. Provisions in the law relating to generation and transmission are closely aligned to this objective. Section 38 of the EA 2003 clearly spells out the requirements of non-discriminatory open access, and the responsibility of the CTU to ensure development of an efficient, coordinated and economical system of inter-State transmission lines for smooth flow of electricity from generating stations to the load centres. The provisions of the law have been built upon further by the Central Government through the national Electricity Policy (NEP) and the Tariff Policy.

3.5.1. PROVISIONS OF THE NATIONAL ELECTRICITY POLICY ON TRANSMISSION

The NEP has several important provisions, which are summarized in the table below:

Table# 4: Relevant provisions of the NEP relating to transmission development and pricing

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.

Para No.	Provision
	* * * *

3.5.2. PROVISIONS OF THE TARIFF POLICY ON TRANSMISSION PRICING

The Tariff Policy builds further on the provisions of the NEP to clearly articulate a roadmap for development of a more contemporary transmission pricing regime. Relevant excerpts of the policy are provided below:

Table# 5: Relevant provisions of the NEP relating to transmission development and pricing

Para No.	Provision
7.1(2)	The National Electricity Policy mandates that the national tariff framework implemented should be sensitive to distance, direction and related to quantum of power flow. This would be developed by CERC taking into consideration the advice of the CEA. Such tariff mechanism should be implemented by 1st April 2006
7.1(3)	Transmission charges, under this framework, can be determined on MW per circuit kilometer 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
7.2	**Transmission Losses** Transactions should be charged on the basis of average losses arrived at after appropriately considering the distance and directional sensitivity, as applicable to relevant voltage level, on the transmission system. Based on the methodology laid down by the CERC in this regard for inter- state transmission, the Forum of Regulators may evolve a similar approach for intra-state transmission.

The key focus of policy is thus on (a) ensuring adequacy of transmission on a proactive basis and (b) appropriate pricing structure to ensure cost-reflectiveness. The issue of losses is being dealt through separate study by IIT – Mumbai. The scope of Mercados EMI's work focuses on the appropriate mechanism for determining transmission charges for the ISTS.

3.6. OTHER ISSUES

In addition to the above drivers of change, there are several other issues and questions that require to be addressed as well. These are summarised as below:

A deeper network ensures greater reliability and lower reserves: Many users benefit from system reliability investments. Certain components of ATS are reliability investments. Current regulations allow pooling of the new ATS assets based on negotiations between the regional partners.

In the event of a beneficiary not being benefited directly from the new ATS, the charges may not be pooled. This would burden the new users excessively and may render new investments uneconomical for these users.

In a large region the usage is not uniform: Postage stamp methodology does not reflect utilization of the network. Eastern parts of Uttar Pradesh are close to large power plants and use transmission resources and cause transmission losses to a lesser extent as compared to Punjab or even eastern parts of Uttar Pradesh. It is therefore, unfair to socialize transmission charges and losses over all beneficiaries.

In certain cases State lines are a part of the meshed grid and need to be compensated: Regional lines and even state lines are a part of the meshed network: Power flows from NER to NR involve flow not only over inter-state lines developed by the Central Transmission Utility but also certain inter-state lines and intra-state lines developed by the state transmission utilities. These may need to be considered in the pricing mechanism for the ISTS in a scientific manner.

Effective congestion management will require changes in pricing: Capacity expansion of the inter-state network is the mandate of the CTU and the CEA in association with the STUs and other stakeholders. The transmission projects can however be implemented by Independent Power Transmission Companies (IPTCs). The current transmission pricing mechanism does not provide sufficient signals for optimal loading levels of the network. Ideally, investments should be guided by the need to relieve congestion and transmission pricing mechanism needs to have a component (based on network congestion) which specifically signals the need for capacity expansion.

The framework proposed should be address future issues that can be foreseen: In particular there is an issue of integration of renewable energy sources in the transmission grid and in the energy markets in a cost effective manner. This issue has been raised in the various proceedings of CERC by certain stakeholders, the contention being that the existing pricing framework places such technologies at a substantial disadvantage instead of encouraging them. To the extent practicable, a new framework should address such aspects as well.

4. MERCADOS' SCOPE OF WORK

Recognising the need to transition to a new transmission pricing framework (which is also a requirement of the policies governing the sector), CERC has commissioned the instant study to evaluate the various options available for pricing of transmission services on the ISTS, keeping in view the configuration of the Indian power system and its operations. Excerpts of the specific scope of work are provided in the box below.

Box # 2: Excerpts on Scope of Services

The consulting agency shall work with the staff of the Commission for preparing a proposal on the issue of sharing of transmission charges. This proposal should inter-alia contain:

- *A brief discussion about the problem at hand*

- *Review of international practices in this regard*

- *Assessment of various options with regard to sharing of transmission charges (including the Zonal Matrix suggested by CEA), their relative advantages and disadvantages and suitability for adoption in India*

- *Addressing requirements emerging due to private sector participation through Competitive Bidding in transmission service*

- *Undertaking Simulation study for various options for transmission pricing*

- *Review of preparedness of CTU/RLDCs from implementation perspective*

- *Any other relevant issue*

- *Recommendations*

The consulting agency shall also consider the views of CEA and CTU on the option recommended by it. The proposal will be put up for comments by the stakeholders. The Commission may hold a public hearing and the consulting agency may be required to present contents of the proposal and compile views of the Stakeholders.

The consulting agency shall frame draft regulations based on the decision taken by the Commission

This discussion paper has been prepared keeping in view the scope of work indicated, and considering the significant body of work already undertaken by the Commission and the Staff. Later sections of this Approach Paper include the proposals that will form the basis for inviting stakeholder views and comments.

It needs to be noted that the scope of work exclusively focuses on the methods of apportioning of the transmission costs among the various users and not on the determination of the costs of the service providers. Thus, irrespective of the method recommended, the transmission service providers would continue to recover their costs on the basis of existing regulations of the CERC and no change whatsoever is expected in this.

5. PROCESS FOLLOWED FOR DEVELOPMENT OF APPROACH PAPER

In developing the discussion paper the engagement team has undertaken the following:

1.   Review of prior work undertaken by various agencies:

A review of the past body of work was undertaken. This review covered:

a) The zone to zone matrix structure developed by CEA as a potential option for pricing of transmission services.

b) Report of M/s ECC in their study on "Bulk Power and Transmission Tariffs and Transmission Regulations", which was submitted to Government of India in February, 1994.

c) Discussion papers prepared by the Staff of CERC, Staff Paper on "Arranging Transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity"

2.   Review of prior work undertaken by the CERC:

A large body of work has already been done by the CERC itself and is available through the orders of the Commission. These include the Discussion Paper in February 2007 on "Proposed Approach for Sharing of Charges for and Losses in Inter-State Transmission System, and the subsequent final order final order in the matter issued on 28th March 2008. Various other orders starting with the Availability Based Tariff order of 2002 were also reviewed to understand and reflect the progressive developments on transmission access and pricing. The Terms and Conditions of Tariff applicable from April 1, 2009 have also been considered.

3.   Review of international practices and contemporary trends

International practices including in Europe, the US, Latin America and China have been reviewed. International members of the Mercados team have direct experience and understanding of developments in these regions. Key learnings from the review have been incorporated in this paper.

4.   Consultation with CEA and CTU

The team developing this paper has had the benefit of extensive consultation, data support and advice of the Power Systems wing of the CEA and the CTU. It needs to be noted that CEA has already undertaken a considerable body of conceptual work, including on the zone to zone matrix

method. The team has had the benefit of invaluable advice and guidance of Member (Power Systems) and other functionaries of the CEA.

5. Discussions with Stakeholders

The CERC called for a presentation by the assignment team at a meeting held on February 10, 2009 in which a number of stakeholders were represented. The study team has had the benefit of advice from this meeting, which has been appropriately reflected.

6. Detailed simulation analysis using load flows

Based on data available from the CEA, the assignment team has developed the load flows and applied the preferred pricing options on the load flows to determine the pricing and evaluate impact. Assistance of the Power Anser Lab, IIT – Mumbai has been invaluable in this regard.

7. Consultation with other experts

The assignment team also consulted a number of independent experts who are knowledgeable about the Indian power system and are conversant with transmission pricing principles and their practicability. Even though such experts are not individually acknowledged here, the assignment team is indeed grateful for their assistance and perspectives.

This discussion paper in effect is a culmination of the steps undertaken till date and is to become the basis for consultation with a wider body of stakeholders on the new arrangements proposed.

III IDENTIFICATION OF PREFERRED PRICING FRAMEWORK

1. OBJECTIVES TO BE ADDRESSED THROUGH NEW FRAMEWORK

Even as the need for change has been identified, it is important to establish certain clear objectives for the new transmission framework. The discussion paper of the CERC issued in February 2007 established some very important principles. These are reproduced below for reference:

i)   Reasonable revenue to the transmission system owners, to enable repayment of loans, payment of interest, return on equity, reimbursement of O&M cost, contingencies, etc.

ii)   Equitable sharing of the above payment between the transmission system users, according to benefits derived (or entitled to derive).

iii) Inducement to transmission system owner to enhance the availability of the system (by minimizing outages).

iv)   Ensuring that merit - order dispatch of generating stations does not get distorted due to defective transmission pricing.

v)   Ensuring that planned development / augmentation of the transmission system, which is otherwise beneficial, does not get inhibited.

vi)   Appropriate commercial signal for optimal location of new generating stations and loads.

vii) Treatment of transmission losses – whether handled separately or as a part of transmission charges.

viii) Priority of transmission system usage between users under different categories.

ix)   Revenue of transmission system owner, in a vertically unbundled scenario, should not depend on dispatch decisions and actual power flows.

x)   To the extent possible, the users should know upfront what charges they would have to pay, and retrospective adjustments should be avoided.

xi)   Dispute-free implementation on a long-term basis

The above principles form a sound basis for developing the pricing framework. The current study addresses most of the requisites established by the Commission, except for aspects like transmission losses, which are being addressed through a separate study.

An added objective/priority identified for the pricing framework is compatibility with the operations of competitive energy markets. Indeed the transmission access and pricing rules should not in any manner inhibit the development of these markets, even if they do not explicitly promote the same. Indeed the role of transmission access and pricing mechanisms should be to be neutral to all kinds of market forms, which would permit users to choose their preferred market mechanisms.

An important factor that has been identified in the Staff Paper of CERC on "Arranging Transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity" is that the transmission access and pricing issues cannot be seen in isolation, and the two need to be considered in unison. This is an important observation and has guided the assignment team in formulating the preferred framework.

2. CHANGE OPTIONS EVALUATED

In the development of transmission pricing structures it important to take into account the role of transmission prices in driving efficient outcomes in the electricity markets. In this context the transmission pricing methods can be broadly classified into those based on (1) differences in locational prices of electrical energy (2) based on the intrinsic cost of the network and congestion therein.

Fig. 3: Generic Transmission Pricing Methodologies
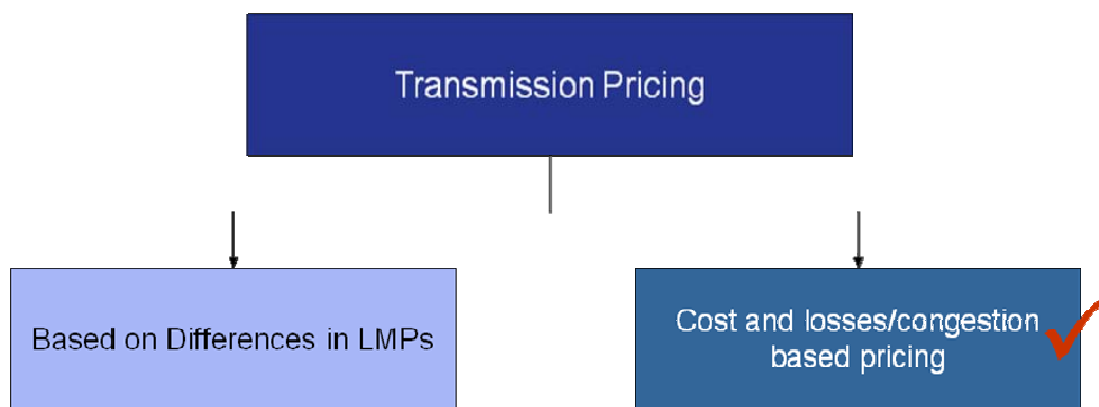
2.1. THE THEORETICAL IDEAL – BASED ON DIFFERENCES IN LOCATIONAL PRICES OF ELECTRICAL ENERGY

Ideally, the price for transmission services should reflect the marginal cost, in both the short run and the long run. Since the short-run marginal cost of the transmission network varies significantly from one dispatch interval to another, this implies that, ideally, transmission prices should vary in real time and should reflect the instantaneous short-run marginal cost of the transmission network. In some international wholesale electricity markets this is achieved by combining the short-run price for the use of the transmission network with the price paid for the generation of electrical energy to form a combined price which varies in real time at different locations across the network. This is known as 'nodal pricing'. Nodal pricing is used in countries such as Argentina and New Zealand and also for the Pennsylvania-New Jersey-Maryland interconnection. Under nodal pricing the differences in the electricity spot prices at different points on the network fully reflect the short-run marginal cost of using the transmission network between those two points. However, in the presence of economies of scale (as in electricity transmission networks), nodal pricing will not recover the total costs of operating the network. Under these circumstances, there is a need to set a tariff that is above the short-run marginal cost. This is often achieved through the fixed component of a 'two part' tariff. These additional charges are intended to provide for the total recovery of the transmission network operators' costs. They are not intended to alter the behaviour of network users. Ideally, this fixed component would be set in such a way as to not distort the production, operation, location, or expansion decisions of network users. In addition, these fixed charges would be broadly stable over time so as to encourage generators and (at least large) loads to make long-term investments, without fear of significant increases in transmission charges in the future. In this theoretical ideal, transmission charges would take two forms and would play two quite different roles:

- the 'variable' charges would be time-varying, geographically differentiated, and linked to the energy price, and would be designed to signal the short-run marginal cost of the transmission network

- the 'fixed' charges would be designed so as to recover the fixed costs of the network in a least-distortionary manner.

2.2. THE PRACTICAL OPTIONS FOR INDIA

The arrangements in the electricity markets in India differ from this theoretical ideal in several important ways. In particular, the Indian electricity markets do not operate as nodal markets. In the regionally-priced markets in India, where real time price of electricity is determined by the frequency linked Unscheduled Interchange (UI) charges fixed by the Central Electricity Regulatory Commission spot prices do not reflect transmission congestion costs.

The objective of transmission prices, in this context, is therefore not only to recover the total annual fixed costs of the network but also to provide signals which reflect the 'utilization' of the transmission assets. For the recovery of fixed transmission charges all the network users are required to pay

- connection charges,

- use of the network charges and

- charges for joint assets and operations (system operation etc.).

Connection charges enable the transmission company to recover the costs involved in providing the assets that afford connection to the transmission system. Connection charges relate to costs of assets installed solely for use by an individual user.

Transmission Use of System Charges (TUOS) reflects the cost of installing, operating and maintaining the transmission system. These activities are undertaken to the standards prescribed by the Grid Code to provide capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

Charges for joint assets and operations go beyond charges for system operation (real time dispatch, energy accounting etc.) and subsidize the transmission connection charges for small environmentally benign generators – benefits of which are shared by all network customers. Certain transmission lines are constructed in anticipation of generation capacity – North Eastern Region of India has huge hydro generation potential all of which is not expected to be commissioned simultaneously. However, charging use of this transmission corridor to the generators which are commissioned initially would render them financially unattractive. The charges for such assets could be shared by all system users since hydro resources enhance energy security, are environmentally clean and hence benefit all users.

Connection charges are directly identifiable based on a clear definition of the boundary between user specific assets and network assets. Beyond the connection charges, there is a role for TUOS to provide locational signals to correct for the absence of price signals in the wholesale spot energy market. This leads to determination of 'utilization' of transmission network based on load flow based methods. Two of such methods commonly used internationally are (i) **Marginal Participation** method, (ii) the **Average Participation** Method. In the Indian context, the **Zone-to-Zone** method proposed by CEA also needs consideration.

Utilization of the network is generally determined in terms of either average utilization or marginal utilization of the transmission assets. Alternatively the methodology proposed by CEA measures utilization based on system losses caused by transactions between various zones. Pricing of transmission services based on average or marginal utilization of the network branches is known as Average Participation and Marginal Participation method respectively. These two methods have been compared and contrasted in detail in the literature. Average participation method requires as its input data a complete set of power flow corresponding to the specific system conditions of interest. This method is based on the assumption that power flows can be traced by assuming that at any node the inputs are distributed proportionally between the output flows. The model therefore identifies physical paths for each generator injecting power into the grid until they reach the loads where the power is consumed. Then the cost of each line is allocated to the different users according to how much of the flows starting at a certain node have circulated along the corresponding line. This makes several assumptions which are not supported by the physical laws of the network. The method of Marginal Participations estimates how flows on various network branches respond to change in injection (or withdrawal) of 1 MW at any node. The agents (generators or distribution companies / large customers) will then be charged their share of the costs of the links on which flows change. These methods are discussed in detail below.

2.2.1. MARGINAL PARTICIPATION METHOD

Any usage based methodology attempts to identify how much of power that flows through each of the lines in the system is due to the existence of a certain network user, in order to charge it according to the adopted measure of utilization. To do so, the Marginal Participation (MP) method analyzes how the flows in the grid are modified when minor changes are introduced in the production (or consumption) of agent *i*, and it assumes that the relationship of the flow through line *j* with the behaviour of the agent *i* can be considered to be linear. For each of the considered scenarios viz., Winter – peak, other than peak, Summer – peak, other than peak, and Monsoon – peak, other than peak, the procedure can be described as follows:

1. Marginal participation sensitivities are obtained that represents how much the flow through each network branch *j* increases when the injection/ withdrawal in a bus is increased by 1 MW. Flow variation in each network branch *j* incurred by 1 MW injection / withdrawal at each bus is computed for each scenario, *e*.

2. Due to the Kirchoff's laws, any 1 MW increase in generation (or load) at node *i* has to be compensated by a corresponding 1 MW increase in load (or generation) at some other node or nodes (Losses are ignored, since most of the studies assume DC load flow for the purposes of these calculations, where line resistance is assumed to be zero). Thus the calculation of how much an injection (or withdrawal) at a certain bus affects the flows in the network depends on the decision of which is the node that responds, and the answer that is demanded from the method is heavily conditioned by an assumption that it needs as an input. Different choices are possible for this 'slack bus' (the responding node in power systems terminology). In cases of countries like Argentina or Chile, the 'slack node' is near the major load centre. For larger networks, distributed virtual nodes can be considered – where all the demand (generation) responds pro-rata to 1 MW increment in generation (load). For the purposes of the computations in the Indian context distributed virtual nodes have been considered.

3. Once the flow variation in each line incurred by each agent and for every scenario is obtained, it is possible to compute a seasonal usage index for each network user. This index is computed according to equation given below. It can be seen that only positive increments in the direction of the power flow in the base case are considered. This implies that increments which reduce burden on lines are neither given any credit nor charged for use of the system. This is essentially because of practical reasons where it could be difficult to pay grid connected entities for being connected to the grid. Further, there could be times (with strictly positive chance) when these entities need to use certain network branches along the direction of the main flow, though such times may not be the times which coincide with typical seasonal system peak and other than peak periods considered in the load flow studies. This is also a standard international practice followed in countries where such pricing mechanisms are used.

   The seasonal index is computed as:

$$U_{e,i,l} = \left(\left| F_{le}^i \right| - \left| F_{le} \right| \right) . P_{ie} .$$
$$\left| F_{le}^i \right| - \left| F_{le} \right| > 0, Sign(F_{le}^i) \text{ is same as } Sign(F_{le})$$

   Where,

   U_{eil} is the seasonal usage index in line *l* due to injection / withdrawal at node *i*

   F_{le} is the flow in line *l* under scenario *e* under base case

   F_{le}^i is the flow in line *l* under scenario e due to injection / withdrawal of 1 MW at node *i*

   P_{ie} is power dispatch / demand at bus *i* under scenario *e* under base case

4. The revenue requirement of each line is allocated pro-rata to the different agents according to their total participation in the corresponding line.

$$Cost\ Allocated_{eil} = \frac{U_{eil}}{\sum_i U_{eil}} \times C_l$$

Where,

C_l is the seasonal aggregate revenue requirement of the line

$\dfrac{U_{eil}}{\sum\limits_{i} U_{eil}}$ is the marginal participation factor

Alternatively, the revenue requirement of the lines can be allocated to nodes based on the extent to which the lines are used. Let the flow on line *l* be *Flow$_l$* and capacity of the line be *Cap$_l$*. Then the cost of the line is allocated according to the following formula:

$$Cost\ Allocated_{eil} = \frac{U_{eil}}{\sum\limits_{i} U_{eil}} \times C_l \times \frac{Flow_l}{Cap_l}$$

Where,

Cost Allocated$_{i,l}$ = Cost of line *l* allocated to agent *i*

In case the line is under loaded, the transmission service providers will not be able to recover the entire cost of the line based on just users of the line. It is proposed that all such costs be recovered on a postage stamp basis from all the users of the network.

The above mechanism is also commonly referred to as the "Point tariff" and has been considered by the CERC in the past as a potential alternative to the regional postage stamp method.

2.2.2. AVERAGE PARTICIPATION METHOD

The method of average participation works as follows:

1. For every individual generator *i*, a number of physical paths are constructed, starting at the node where the producer injects the power into the grid, following through the lines as the power moves through the network, and finally reaching several of the loads in the system.

2. Similar calculations are also performed for the demands, tracing upstream the energy consumed by a certain user, from the demand bus until some generators are reached. One such physical path is constructed for every producer and for every demand.

3. In order to create such physical paths, a basic criterion is adopted: A rule allocates responsibility for the costs of actual flows on various lines from sources to sinks according to a simple allocation rule, in which inflows are distributed proportionally between the outflows. The main attractions of tracing are that the rule has some theoretical backing based and does not require the choice of a slack node. The drawbacks of tracing are first that aggregation of users can lead to counterintuitive results: if generation and load or different nodes are aggregated, then they are exposed to different tariffs. Second, the choice of the allocation rule is decisive but apparently arbitrary. An illustrative example of the proportional allocation mechanism is demonstrated in Fig. # 4 below.

Fig. #4: Average Participation Method

$$30 \times \frac{40}{(60+40)} = 12$$
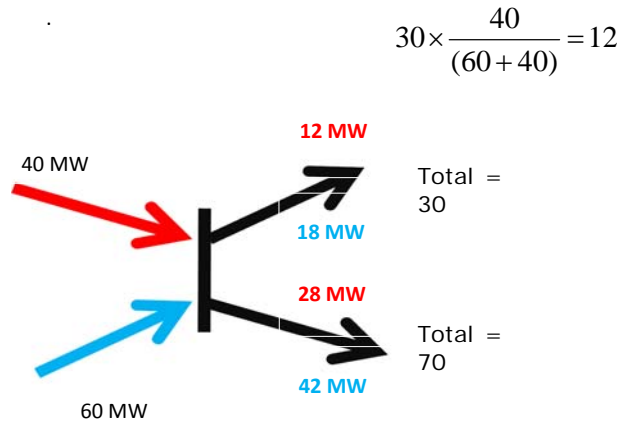
The average participation method calculates the participation of agent *i* by tracking the influence in the network of a transit between node *i* and several ending nodes that result from the rules that conform the algorithm. In the example above, based on flow in the outgoing lines, the injection of 40MW (through the red line) is allocated to the outgoing lines in the proportion of the transfers from the two outgoing lines. Thus the outgoing line that transfers 30 MW (i.e, 30% of the total transfer out of the bus) is allocated 30% of the 40 MW injection from the red line, i.e., 12 MW. Similar allocations are made for the other flows as well.

2.2.3. CEA ZONE TO ZONE METHOD

In the CEA zone-to- zone method, the country is divided into 12 zones (A-L), the transmission charges are computed as follows:

$$TC = \frac{MTSC}{GZS} \times G_{ij} \times ZS_{ij}$$

Where,

MTSC	=	Monthly Transmission Service Charges for the National pool
G_ij	=	Generation capacity allocated to National pool (gross IC) from zone i to zone j
Ndays	=	Number of days in the month (30 or 31 or 28 or 29)
Zij peak	=	Zonal Matrix transmission stamps for allocation from zone i to zone j for peak hour period of the season of the month
Zij o-t-peak	=	Zonal Martix transmission stamps for allocation from zone i to zone j for other than peak hour period of the season of the month
ZS_ij	=	Zij peak * 8 * Ndays + Zij o-t-peak * 16 * Ndays
GZS	=	Sum of all products of inter-state G_ij and ZS_ij
	=	Σ G_ij * ZS_ij

The zonal matrix of transmission stamps (Zij) are computed by injecting 100 MW at node X and withdrawing at another node Y. The impact of injection and withdrawal is recorded in the following matrix (illustrative):

FROM STATES V	TO --->	A	B	C	D	E	F	G	H	I	J	K	L
JK,PB,HP,CH,HR,DE	A	98.9	96.6	111.4	97.0	94.0	109.6	98.4	96.7	100.0	126.8	131.7	171.3
Rajasthan	B	100.8	98.8	114.0	99.1	96.1	112.3	100.5	98.8	102.2	130.2	135.2	177.7
UP, Uttranchal	C	88.9	87.1	99.0	87.5	85.1	97.6	88.6	87.3	89.9	111.1	114.7	143.9
Maha, Goa	D	100.2	98.0	113.2	98.9	95.7	111.6	100.3	98.6	102.0	129.4	134.2	175.9
Guj, D&D,DNH	E	103.3	101.2	117.3	101.8	98.8	115.6	103.3	101.5	105.1	134.7	139.8	185.7
MP, Chattisgarh	F	90.0	88.1	100.2	88.6	86.2	99.0	89.8	88.4	91.2	112.8	116.4	146.7
TN,Kerala,Pondi	G	97.9	95.8	110.3	96.6	93.5	108.8	98.9	97.0	100.3	125.5	130.1	169.0
Karnataka	H	99.7	97.5	112.5	98.4	95.2	111.0	100.6	98.9	102.2	128.6	133.3	174.3
Andhra Oradesh	I	96.5	94.4	108.4	95.2	92.2	107.0	97.2	95.5	98.9	123.1	127.6	164.7
Orissa	J	80.9	79.4	89.2	79.7	77.7	88.1	80.7	79.5	81.7	99.1	101.8	124.1
Bi,Jhar,DVC,WB,Sikm	K	79.2	77.8	87.1	78.0	76.1	86.0	78.9	77.8	79.9	96.3	99.1	120.2
NER	L	69.0	67.9	74.9	68.1	66.6	74.0	68.7	67.9	69.5	81.5	83.5	99.3

In the above matrix, the "from" states indicate the injection zones and "to" states indicate the withdrawal zones. The entries in the above matrix indicate the power withdrawn in each "to" zone corresponding to the injection in each "from" zone.

The elements in the above matrix are subtracted from 100, to reflect the network gain/loss due to transmission losses / congestion. The negative elements in the matrix thus obtained are collared at zero. The matrix so transformed is presented below:

FROM STATES V	TO --->	A	B	C	D	E	F	G	H	I	J	K	L
JK,PB,HP,CH,HR,DE	A	1.1	3.4	0.0	3.0	6.0	0.0	1.6	3.3	0.0	0.0	0.0	0.0
Rajasthan	B	0.0	1.2	0.0	0.9	3.9	0.0	0.0	1.2	0.0	0.0	0.0	0.0
UP, Uttranchal	C	11.1	12.9	1.0	12.5	14.9	2.4	11.4	12.7	10.1	0.0	0.0	0.0
Maha, Goa	D	0.0	2.0	0.0	1.1	4.3	0.0	0.0	1.4	0.0	0.0	0.0	0.0
Guj, D&D,DNH	E	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP, Chattisgarh	F	10.0	11.9	0.0	11.4	13.8	1.0	10.2	11.6	8.8	0.0	0.0	0.0
TN,Kerala,Pondi	G	2.1	4.2	0.0	3.4	6.5	0.0	1.1	3.0	0.0	0.0	0.0	0.0
Karnataka	H	0.3	2.5	0.0	1.6	4.8	0.0	0.0	1.1	0.0	0.0	0.0	0.0
Andhra Oradesh	I	3.5	5.6	0.0	4.8	7.8	0.0	2.8	4.5	1.1	0.0	0.0	0.0
Orissa	J	19.1	20.6	10.8	20.3	22.3	11.9	19.3	20.5	18.3	0.9	0.0	0.0
Bi,Jhar,DVC,WB,Sikm	K	20.8	22.2	12.9	22.0	23.9	14.0	21.1	22.2	20.1	3.7	0.9	0.0
NER	L	31.0	32.1	25.1	31.9	33.4	26.0	31.3	32.1	30.5	18.5	16.5	0.7

The elements of the above matrix are further scaled between 0-18. The zero (0) entries in the matrix so obtained are collared at 4 for determining the Z_{ij} matrix used for computation of transmission charges.

FROM STATES V	To --->	A	B	C	D	E	F	G	H	I	J	K	L	M
JK,PB,HP,CH,HR,DE	A	4	4	4	4	4	4	4	4	4	4	4	4	4
Rajasthan	B	4	4	4	4	4	4	4	4	4	4	4	4	4
UP, Uttranchal	C	6	7	4	7	8	4	6	7	5	4	4	4	6
Maha, Goa	D	4	4	4	4	4	4	4	4	4	4	4	4	4
Guj, D&D,DNH	E	4	4	4	4	4	4	4	4	4	4	4	4	4
MP, Chattisgarh	F	5	6	4	6	7	4	5	6	5	4	4	4	5
TN,Kerala,Pondi	G	4	4	4	4	4	4	4	4	4	4	4	4	4
Karnataka	H	4	4	4	4	4	4	4	4	4	4	4	4	4
Andhra Oradesh	I	4	4	4	4	4	4	4	4	4	4	4	4	4
Orissa	J	10	11	6	11	12	6	10	11	10	4	4	4	8
Bi,Jhar,DVC,WB,Sikm	K	11	12	7	12	13	8	11	12	11	4	4	4	9
NER	L	17	17	14	17	18	14	17	17	16	10	9	4	14

In the above matrix additional column "M" is added. The elements of the "M" column are determined by averaging the zonal stamps in other columns. The stamps in column "M" are used to determine transmission charges for short term transactions.

3. SELECTION OF PREFERRED FRAMEWORK

The basic objectives that the new transmission pricing framework needs to serve have already been discussed in Section III earlier. These would need to be developed adequately for understanding their implications in practical terms. In particular we believe that any pricing formulation must be guided by the following core principles:

a. **Cost-reflectiveness:** The charges should closely reflect the nature of usage of the network and be based on the appropriate economic principles of cost of use determination and allocation. In case of the average participation (AP) method, the assignment of responsibility is based on the forecasted patterns of flows. The MP method on the other hand uses a load flow model to calculate the effect on the use of network elements of the incremental injections into and withdrawals from the grid. The results obtained from these methods are independent of the location of political borders of the states, making these methods fully consistent with the concept of single paradigm under 'National Electricity Markets'. The MP method is able to detect those injections (or withdrawals) and hence flows which reduce the overall flows on specific network elements and therefore have a beneficial effect on the utilization of such assets. The transmission prices so determined encourage injection (withdrawal) at nodes which reduce the incremental burden on the network flows. The AP method does not explicitly take into account the benefits that a generator (or a distribution company) may obtain from reducing the burden on the network. The Zone-to-Zone method of CEA allocates annual charges of transmission based on losses and congestion. Since the costs of the network are allocated on the basis of losses (which effectively reflects the squared value of the length of line utilised), the Zone to Zone method tends to return higher estimates of cost allocation as compared to the AP and MP methods.

b. **Equity:** The cost-reflectiveness objective might lead to a large dispersion in transmission prices for access to the networks from various locations. Equity is normally measured in terms of the variance is transmission use of system charges determined using the above methods. While, all the methods can potentially lead to high variance in transmission use of system charges, the variance is mitigated and hence equity aspects are addressed through other components of transmission charges which are based on postage stamp methods of allocation. Further, if socio-political and economic conditions of a geographical area require lower transmission charges, the equity concerns may be addressed through government intervention by explicit subsidies without disturbing the price signals generated by the above mechanisms. However, to the extent possible, the method selected should reduce the need to extraneous policy or subsidy interventions. The MP method returns the best results since the dispersion of values is the least in this method.

c. **Locational Signals for location of generation and demand:** All the methods provide strong signals for location of generation and demand. The signals are more pronounced in the case of MP and the CEA zone-to-zone method. While the MP method gives an explicit signal for location of generation and demand, in the case of AP method and zone-to-zone approach, the ratio of the split of transmission charges for each asset needs to be exogenously supplied to the model. The purpose of long-term locational signals is, in principle, to provide a prospective price signal, in terms of current and future network infrastructure costs, to existing and potential generators and/or consumers connected to the network. Whilst, of course, other factors, such as availability of primary energy source, availability of other resources, environmental aspects, site suitability, etc, also play an important role, such a long-term signal with respect to transmission access would be designed to have an influence on future decisions regarding the siting of both generation capacity and consumption in this regard. As a result, for instance, continuation of existing and additional new generation in regions of surplus generation would in principle be discouraged through higher network access charges to be paid by generators. In turn, generation in regions of surplus consumption would be encouraged through lower access charges, which would provide the appropriate long-term locational signal.

d. **Suitability in the context of the highly meshed Indian grid**: The AP method and the zone-to zone methods are universal in their application to small or large power systems, MP

method can be appropriately applied to large power systems only when distributed virtual slack nodes are considered for absorption (or generation) of 1 MW on incremental generation (load). MP method with only one slack node is normally applied to smaller power systems. For the present exercise, multiple slack nodes have been considered to suit the method to the Indian grid. Hence from a suitability grid standpoint all methods are evenly placed.

e. **Technical Soundness:** This connotes minimization of arbitrary assumptions and procedures. All the above methods are based on some fundamental assumptions. The proportionate attribution of flows at various nodes in the case of AP method does not reflect the physics of actual flows. In the MP method, the laws of physics are closely adhered to – however the assumptions and modeling of the slack nodes in the system is of importance. The zone-to-zone method determines utilization of the network and hence transmission charges based on the direction of commercial energy contracts. This may not reflect the network utilization in accordance with the physical laws, although the method could be a more appropriate basis for determining system losses. Further, the allocation of transmission charges between generation and demand is done endogenously in the MP method. In other methods the relative burden of transmission charges between generator and demand needs to be exogenously specified. A prudent choice of method is therefore based on the view of various stakeholders. Our view, however, holds in favor of the MP method.

f. **Transparency**: The pricing framework must be transparent to ensure that there is adequate appreciation among the users on the basis of pricing or any changes thereto. Along with the transparency of the principles and practices, the information used for determining actual levels should be transparently available. Both the MP and the AP methods are adequately transparent and easy to understand. Determination of utilization of transmission assets and hence allocation of transmission charges based on losses and congestion lend a degree of opacity to the zone-to-zone method.

g. **Suitability for long term, short term and spot transactions**: When power injected or withdrawn from a grid at any location, the utilization of the network assets is independent of the nature of commercial contract which enables that generation or withdrawal, i.e., a 100 MW injection (withdrawal) at a location at a particular time would use the network in a manner which is independent of when and how the electricity was contracted for. This implies that the transmission charges for use of the network due to generation (withdrawal) at a particular location at a particular time should be charged the same transmission charges independent of whether the contract is long term/ short term of a spot transaction. However, in the case of network congestion, the transmission charges must also reflect the 'value of the transmission resource' for a customer rather than just the cost of the underlying assets that are being used. In this case auction of transmission rights could be resorted to, to obtain the price of the underlying asset. It may be noted that system losses depend on the long term /short term nature of procurement and hence may be charged separately, but the same is beyond the scope of this paper, since the matter of losses are being dealt with separately.

h. **Predictability**: Unless there are major unforeseen investments that take place in a year, seasonal transmission charges for peak and other than peak conditions can be reasonably determined for a year. All the three methods are predictable to the same extent as they utilize the same basic engine – the load flow analysis – for the determination of transmission charges. To improve predictability and minimize deviations from the cost forecast, the frequency of revision of the charges could be altered appropriately.

i. **Implementability**: As a final criterion, the pricing framework should be implementable within the technical and institutional capacity that exists. Unless large scale changes are warranted by other factors, existing infrastructure should be utilised to the extent possible to implement the new charges. All the three methods are equally implementable, and do not require special infrastructure beyond what already exists on the ISTS.

In its development of transmission pricing structures it important to take into account the role of transmission prices in driving efficient outcomes in the electricity markets. Further, the mechanism must attempt to balance the efficiency and equity concerns in the context of socio-economic context of the country. A comparison of above methodologies in terms of the attributes in presented in Table # 6 below. A comparison with the present regional postage stamp method has also been simultaneously provided for reference.

Table # 6: Comparison of alternative transmission pricing mechanisms on Attributes

	Average Participation	Marginal Participation	Zone-to-Zone	Regional postage stamp method
Cost-reflectiveness	Based on flow patterns caused by all network users	Based on incremental use of network assessed through load flows	Based on losses/congestion	Transmission charges do not reflect network utilization
Equity	Could increase burden on intervening states due to proportionate allocation of costs	More equitable than other methods due to allocation on the basis of incremental use	Since losses are the basis of cost allocation, long distance transactions could face significantly higher charges. Can be corrected by using min-max fairness or other game theoretic techniques	Transmission charges are the same for all the users in a region
Locational signals for investment	Weak locational signals	Provides good locational signals in terms of transmission charges	Provides good locational signals in terms of transmission charges. Strongly signals congestion	Provide no signal for efficient investment in generation or demand in terms of transmission charges
Suitability in the context of highly meshed Indian Networks	Adequate	Adequate	Low investment in transmission could lead to higher losses and congestion and therefore increase the size of zonal stamps. Reduction in stamp values to reduce variations among regions would need to be significantly compensated by an 'uplift' charge	Have been successfully used till now, but with the formation of the national grid, may no longer meet the efficiency requirements of transmission pricing
Technical Soundness – minimization of arbitrary assumptions or procedures	May not strictly reflect the laws of physics. May however reflect a reasonable simplification	Adheres better to the laws of physics. Allocation depends on the selection of slack nodes	Adheres closely to the laws of physics for loss allocation. Uses losses and congestion between injection and withdrawal nodes to allocate fixed transmission charges	Does not relate to physical laws of the network flows
Transparency – should be easily understood	As per intuition since it reflects flows. However may lead to	Reasonably transparent due to use of use of load flows	Uses losses to allocate fixed transmission charges, which	Is easily understood, though hides the extent of network

	Average Participation	Marginal Participation	Zone-to-Zone	Regional postage stamp method
and verified	excessive burdening of heavily transited states, even when the load and generation in these states are balanced	with limited approximations	can result in need for high degree of adjustments to limit extreme values	usage in terms of distance and direction by each user of the transmission network
Suitability for long term, short term and spot transactions	No difference between short term and long term use	No difference between short term and long term use	Short term transactions get significantly higher costs *if* incremental losses are used as basis	Transmission charges for short term access need to be determined
Year-to-Year changes anticipated in rates	Likely to remain stable unless there is significant change in power flows (Not too much practical experience available)	Likely to remain stable unless there is significant change in power flows	Likely to remain stable unless there is significant change in power flows	Changes with changes in ARR of the transmission company
Implementation – should be reasonably straightforward and cost-effective to implement	Not difficult if principle is accepted by users (Analysis is limited to a number of representative hourly snapshots). Impact analysis necessary	Not difficult if principle is accepted by users (Analysis is limited to a number of representative hourly snapshots). Impact analysis necessary	Not difficult if principle is accepted by users (Analysis is limited to a number of representative hourly snapshots). Impact analysis necessary	Implementation is easy though there may be issues regarding fairness in the context of large networks.

A comparison of the above methodologies of the attributes suggests that each methodology has its own advantages and disadvantages. However, global experience with practical implementation suggests a serious consideration of the Marginal Participation Method in the Indian context.

4. CONTEMPORARY INTERNATIONAL EXPERIENCE

Ideally, transmission charges must reflect the 'value' of the transmission assets in terms of the price of energy. Value of intervening transmission assets is normally captured by the differences in locational marginal prices (LMP) at various nodes in the grid. The differences in LMPs reflect the losses and congestion in the transmission system. It has been observed in markets where energy at each node is priced at LMP that the revenue collected from these differences in LMPs can recover only up to 20% of the approved regulated costs of the transmission companies. The balance of the revenue must be recovered as fixed charge. If the short term signals generated by the differences in LMPs sustain over a long period, they provide a signal for capacity addition in transmission / generation / demand. However, if the differences in LMPs are not stable, the differences cannot be construed as signals for capacity increases.

Further, in markets where prices of energy are based on uniform market prices, the short term signals cannot be generated. Allocation of fixed charges therefore is the only medium to generate signals for efficient use and development of transmission networks. In what follows, the paper focuses on markets which use one of the proposed methodologies, viz., the Marginal Participation method, Average Participation method and the zone-to-zone method.

As discussed earlier, the Marginal Participation method, in our opinion is most suitable in the Indian context. There is some international experience with Average participation method and little with zone-to-zone method. In the following, we discuss the transmission pricing mechanism in United Kingdom (a variant of the MP method) and Australia (a variant of the AP method).

FRAMEWORK IN UNITED KINGDOM

National Grid is required to apportion its assets to one of two charging categories:
- o   Transmission Network Use of System charges and
- o   Connection charges.

All users of the National Grid are signatories to the Connection and Use of System Code (CUSC). The CUSC is a multi-party document creating contractual obligations among and between all Users of the GB transmission system, parties connected to the GB transmission system and National Grid.

Contractual Framework

- Persons wishing to use and/or connect to the GB transmission system are required to accede to the CUSC by signing the Framework Agreement and enter into a Bilateral Agreement with National Grid.
- The CUSC and individual User's Bilateral Agreements set out the terms and conditions applicable for use of and/or connection to the GB transmission system. In particular, they set out the User's obligations to:
    - o   pay all use of system and connection charges;
    - o   comply with the provisions of the Grid Code;
    - o   sign on to the Balancing and Settlement Code (BSC);
    - o   enter into an appropriate Mandatory Services Agreement.
- Each Bilateral Agreement details the information on which the User's connection charges are based.
    - o   Bilateral Agreement lists the connection assets by description, age and allocation to the User;
    - o   Identifies the connection charges;
- If a User fails to fulfil obligations, entitlement to use and/or be connected to the GB transmission system will cease. The User will be liable for all charges that may arise up to the end of the Financial Year and, for connection, the appropriate Termination Amount.
- When a User applies for a new use of system agreement or to modify an existing use of system agreement they may be required to enter into a Construction Agreement.

Tariff Determination Principles

The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges reflect the impact that Users of the transmission system at different locations have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

For any changes in generation and demand on the system, National Grid must ensure that it satisfies the requirements of the Security Standard. Capital investment requirements are largely driven by the need to conform to this standard. The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' Transmission Entry Capacities (TECs) accommodated. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system at the time of peak demand. The charging methodology therefore recognizes this peak element in its rationale.

National Grid Corporation's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, National Grid is required to reduce TNUOS charges paid by eligible small generators by a designated sum, which is determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery aims to ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year.

Transmission Network Use of System Tariff

The TNUOS has two components:

- A locationally varying element derived from the DC Load Flow (DCLF) Incremental Cost Reflective Pricing (ICRF) transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations.

- A non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUOS tariff.

The DCLF - ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment.

Inputs to the Model

The transmission model used in the UK requires a set of inputs representative of peak conditions on the transmission system:

o Nodal generation information
o Nodal demand information
o Transmission circuits between these nodes
o The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
o The ratio of each of 132kV overhead line, 132kV cable, 275kV overhead line, 275kV cable and 400kV cable to 400kV overhead line costs to give circuit expansion factors
o Identification of a reference node

Information requirements

- **Nodal Generation Information**: The method requires contracted capacity based year ahead statement, plus quarterly updates received by October of the year previous to the charging year.

- **Nodal Demand Information:** Nodal demand data is initially based on Grid Supply Point (GSP) demand that Users have forecast to occur at the National Grid Peak Average Cold Spell (ACS) demand. This is adjusted for the charging year based on the data received in the previous year.

- **Transmission Network Data:** Transmission circuit data for charging year is initially based on data taken from National Grid's Seven Year Statement complemented with the October updates every year. The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) cabled routes and overhead line routes, (ii) 132kV and 275kV routes, (iii) 275kV routes and 400kV routes, and (iv), uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically 400kV cable, 275kV overhead line, 275kV cable, 132kV overhead line and 132kV cable) is more expensive than for 400kV overhead line.

Calculation of Zonal Charges

Number of generation zones is 20 and are computed in terms of marginal km of use at each node. Demand zone boundaries are fixed and relate to the GSP Groups used for energy market settlement purposes. The nodal marginal km are amalgamated into zones by weighting them with their relevant generation or demand capacity. A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of National Grid that zones are fixed for the duration of a price control period (5 years), it could become necessary in exceptional circumstances to review the boundaries that have been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

- Zones should contain relevant nodes whose marginal costs (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

- The nodes within zones should be geographically and electrically proximate.

- Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

Deriving the final £/kW tariff

The zonal marginal kms derived are converted into costs and hence a tariff by multiplying by the Expansion Constant and the Locational Security Factor. For Generation the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff.

For demand the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff. These initial transport tariffs are multiplied by the expected metered triad demand and generation capacity to gain an estimate of the initial revenue recovery.

The Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. This has been determined to be 27:73 for generation and demand respectively.

(i) Residual Tariff

In normal circumstances, the revenue forecast to be recovered from the corrected transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made.

In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational Residual Tariff for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the corrected transport tariffs so that the correct generation/demand revenue split is maintained and the total revenue recovery is achieved.

(ii) Final £/kW Tariff

The final TNUOS tariff is the sum of the Locational and the non-locational residual component. If the Final demand TNUOS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones. The factors which will affect the level of TNUOS charges from year to year include

- the forecast level of peak demand on the system,

- the Price Control formula (including the effect of any under/over recovery from the previous year),

- the expansion constant,

- the locational security factor,

- changes in the transmission network and changes in the pattern of generation capacity and demand.

FRAMEWORK IN AUSTRALIA (ELECTRANET)

As mentioned, the framework used in Australia is a variant of the AP mechanism. Annual Aggregate Revenue Requirements (AARRs) are recovered from the transmission charges for following categories of transmission services:

- Prescribed Entry Service
- Prescribed Exist Services
- Prescribed Transmission use of system services

Cost Allocation

Assets are allocated between prescribed entry services, prescribed exit services, prescribed TOUS services and prescribed common services. The optimised replacement cost of the asset is the cost of meeting the current (and projected future) supply needs with the most technically efficient design and configuration of the asset based on the existing system configuration. Calculation of attributable cost shares is based on assets allocated to each type of prescribed transmission service.

Calculation of Prescribed Transmission Service Price

Once the costs are computed, the next step is to allocate the AARR to each service. This results in Aggregate Service Revenue Requirement for each service (ASRR). AARR is multiplied by the Attributable cost share for each service to determine Annual Service Revenue Requirement (ASRR). This includes the shares for:

(i) Prescribed Entry Service: The ASRR for prescribed entry services is allocated to each transmission network connection point in accordance with the attributable connection point cost share.

(ii) Prescribed Exit Service: The ASRR for prescribed exit services is allocated to each transmission network connection point in accordance with the attributable connection point cost share.

(iii) Prescribed Transmission Use of System Services: The prescribed TOUS services ASRR is recovered from:

- Prescribed TOUS services (Locational Component), and
- Prescribed TOUS services (adjusted non-locational component).

For allocation of the locational component, proportionate use of the shared network is computed using the modified Cost Reflective Network Pricing (modified CRNP) model. This model requires the following inputs:

- An electrical (load flow) model of the network
- A cost model of the network (cost allocation methodology)
- An appropriate set of load/generation patterns.

The model used computes the utilization factors of each network pricing branch over a range of operating conditions. Utilization factors are based on maximum flow on each network component.

The Cost Reflective Network Pricing (CNRP) cost allocation process requires detailed network analysis and involves the following steps:

1. Determination of the annual revenue requirement (ARR) for individual transmission shared network assets;
2. Determination of the network load and generation pattern;
3. Performing a load-flow to calculate the MVA loading on network elements;
4. Determination of the allocation of generation to loads;

5. Determination of the utilisation of each asset on the network by each connection point;

6. Allocation of the revenue requirement of individual network elements to each user based on the assessed usage share

The lumpsum dollar sum is divided by the product of the number of days in the forthcoming financial year and the contract agreed maximum demand (prevailing at the time the transmission prices are published) to calculate the locational price at each connection point providing prescribed TOUS services expressed as $/MW/day.

A significant assumption in the use of the CNRP methodology is the allocation of generation to load using the 'electrical distance'. With this approach, a greater proportion of load at a particular location is supplied by generators that are electrically closer than those that are electrically remote. The 'electrical distance' is the impedance between the two locations, and this can readily be determined through a standard 'fault level calculation'. Once the assumption has been made as to the proportion that each generator actually supplies each load for a particular load and generation condition (time of day) it is possible to trace the flow through the network that results from supplying each load (or generator).

The utilisation that any load makes of any element is then simply the ratio of the flow on the element resulting from the supply to this load to the total flow on the element made by all loads and generators in the system.

In several other countries variants of MP method are currently employed. These include Colombia and Brazil (which is a large country with a federal structure similar to India). Average Participation Scheme is used by Peru and by the Central American Regional Market.

IV PRICING MECHANISM UNDER SELECTED FRAMEWORK

As indicated in the previous sections, based on the review of the Indian system, the MP method has been found to be most appropriate. This method has already been discussed in earlier CERC proceedings (referred to as Point Tariff) as a potentially feasible option, and the present study has confirmed from the instant study. Marginal Participation method has clear advantages over other alternatives considered. These are discussed in section II (3). The key advantages are summarized below:

- MP method defines the usage of each network branch by an agent in terms of the marginal benefit of that branch to the agent. The marginal benefit of a network branch is computed in terms of the increment in flows on that network branch if the generation / demand by that agent were to marginally increase. Therefore marginal usage of each network branch by an agent is equal to the marginal benefit that the agent will derive by increasing its generation / consumption. The charges thus determined reflect the 'value' of the resource for each network user and hence promotes efficiency in the use of the scarce resources – termed as allocative efficiency.

- MP method directly computes the relative use of each network branch by generators and demand customers. The split of transmission charges between generators and demand customers needs to be exogenously specified in other models. This provides clear signal locational signals to generation and demand customers. The importance of such signals is discussed in section II (3c).

- Utilization of the network branches as determined in MP method is based on actual power flows on the network. This obviates the need for arbitrary assumptions such as those required for average participation method.

This section provides the specific study results based on the load flows conducted and using the MP methodology.

1. PROCESS OF DETERMINATION OF ALLOCATION FACTORS AND TRANSMISSION USE OF SYSTEM CHARGES

It is essential to test out the method through practical application for determination of the charges. The MP method (and indeed all the other methods shortlisted) relies on load flows. The inputs to this model are:

- Nodal generation information

- Nodal demand information

- Transmission circuits between these nodes

- Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch

- The associated lengths of each line

- Identification of reference nodes

For this the data of inter-state transmission system (400 kV, 220 kV and some 132 kV branches) was procured from the Central Electricity Authority (CEA). The data reflects the expected topology of the Indian power system at the end of the XI five year plan. The data includes power transmission system branch data (Resistance, Reactance and Line Charging), line capacities, transformation capacity, transformer reactances, shunt reactors and capacitors, minimum and maximum reactive generation capacities of various generators. Seasonal data for typical peak and other than peak time period during winter, summer and monsoon includes generation and demand at various buses in the Indian network. The data was used by CEA for planning purposes in the preparation of the National Electricity Plan for the XI five year plan. The data on line capacities, which was not a part of the

original data set, were determined by computing the Surge Impedance Loading (SIL) of each line and the MW thermal rating of the line. Minimum of the two was taken as capacity of the line. Manual on Transmission Planning Criteria prepared by Central Electricity Authority was used as a reference for the above computations. Line length, which was not a part of the original data set, was determined based on the technical line parameters. Virtual distributed reference node is used in the above analysis.

Using this baseline network, the model calculates for a given injection of 1MW of generation / withdrawal at each node, with a corresponding 1MW offtake (demand) / generation at the reference node (assumed to be a distributed virtual reference node in the present analysis), the increase or decrease in total flows on each network branch. "Virtual distributed node" implies that for 1 MW injection demand at all the demand nodes is increased in proportion of the demand in the baseline case. Similarly, 1 MW of withdrawal at each demand node is compensated by generation at each generation node in proportion of generation in the baseline case.

The simulations were carried out jointly with Power Anser Laboratory at IIT Bombay, Mumbai.

The following steps were followed:

1. AC Load flow for the entire Inter-state transmission network was run using the data provided by CEA. The results so obtained were matched with the load flow results provided by CEA. The real power flows on various lines and the voltage angles between various nodes matched closely with the data provided by CEA.

2. DC load flow analysis was done to compute the base case line flows.

3. The HVDC lines have been treated by replacing them by AC lines of same capacity and costs. Load flow analysis is first performed by replacing HVDC line with an equivalent load at the injection node and equivalent generator at the withdrawal node. Voltage angles are computed at each of the terminal buses. Given the power flow in the base case and the voltage angles, the reactance of equivalent AC line is determined. AC line with the parameters so determined is used for the determination of transmission charges.

4. Using DC load flow, marginal participation factors are computed for determination of transmission system utilization due to marginal injection / withdrawal at each generator / demand node.

5. Aggregate revenue requirement for each line is computed by assuming representative values of capital costs of the lines and associated bays at various voltage levels. Aggregate revenue requirement (ARR) for each line has been obtained by applying the CERC norms for the determination of the fixed transmission tariffs[1]. It is further proposed that the ARR of the transmission assets expected to be commissioned in the next 6 months would be incorporated on the basis of benchmarked capital cost being shortly notified by CERC. Any difference from actual determined ARR would be trued up in the next period.

6. Summer months have been taken from March to June, Monsoon months from July to October and Winter months from November to February. Peak hours have been taken from 07:00 hours to 10:00 hours in the morning and from 17:00 to 22:00 hours in the evening and all the other hours have been taken as other than peak hours.

7. Annual ARR of each line is then attributed to peak and other than peak periods of each season based on the flow in that line during that period in that season. Therefore, ARR of a line to be recovered during period when the flow on that line is higher is more than that recovered during other periods.

8. The ARR (of each period in each season) of each line is attributed to the total change in flow in each line. Therefore the ARR is allocated to each agent in proportion of the change in the flow in network branch affected by that agent. Therefore, if the total changes in flow is less than the capacity of the line, full ARR of the line can still be recovered.

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[1] In order to avoid over-recovery by the transmission companies, when the methodology is applied in practice the aggregate revenue determined is scaled up/down to meet the regulated aggregate revenue requirement of the transmission utilities providing the ISTS transmission services.

9. Total amount to be recovered in paise/hr from each node in each season is computed. The detailed results for each state are provided in Table A.1 in Appendix A.

10. Total amount to be recovered from generators and demand in each state is computed by aggregating the amount to be recovered from all the nodes in each state.

11. In case of over / under recovery of charges for assets attributed to transmission use of the system charges, the charges are adjusted pro-rata to ensure recovery of regulated ARR for the transmission company. The ARR for transmission projects belonging to state utilities or independent transmission service providers will have to be reimbursed to them by the appropriate entity nominated by the CERC.

2. CREATION OF ZONES

The proposed mechanism is based on a locational point charge (Rs/MW/month) for each grid connected entry, which entitles it to access the entire network. In practice it is indeed cumbersome from an implementation perspective in view of the large size of the Indian power system. In some instances it may be inappropriate to apply the pricing at each node in the network since certain local peculiarities could distort pricing signals. Hence a logical basis for aggregating the charges in a region into zones is necessary.

The principles of zoning of such charges typically followed in countries where such methodologies have been implemented are articulated below:

- Zones should contain relevant nodes whose marginal costs (as determined from the output from the computation model) are within a logical range.

- The nodes within zones should be geographically and electrically proximate.

- Generation and demand are separately zoned. Even as it is preferable to have similar zones for generation and demand, this should be pursued only when practical, and other conditions for zoning are met

In the context of India it may be necessary to consider state boundaries, but only to the extent that such consideration makes implementation easy, and does not distort the locational signals.

3. DETERMINATION OF ALLOCATORS BY ZONE

Based on the approach articulated and utilizing the network topology, generation and load anticipated (including the seasonality factors) by the end of the XIth Plan, a sample set of allocation factors have been determined for each node in the system. The network data has been then logically grouped for generation and demand. The transmission access charges are determined for each generation / demand access at each bus. However, for the ease of implementation and management, buses have been aggregated into zones based on principles discussed in the previous sub-section. The total number of generation access zones created is 30 and the number of demand access zones is 27.

Based on this the sample allocators for generation and load zones are presented in the graphs below. The detailed logic for zoning by state and region has been provided in Annex 1 of this document.

Fig. 5: Average Annual Transmission Access Charges payable by Generators (30 Zones)
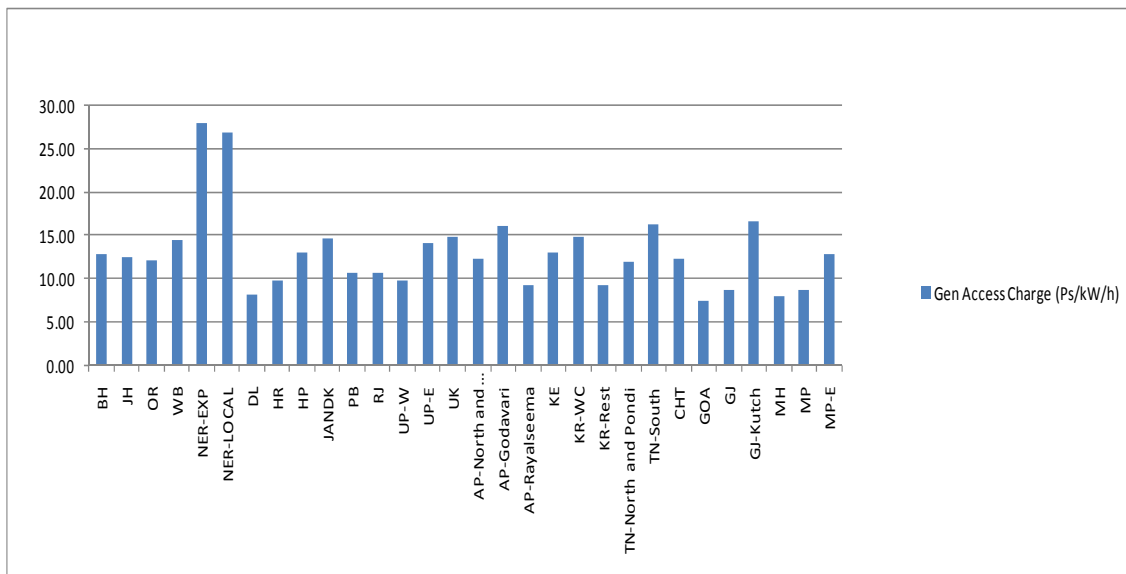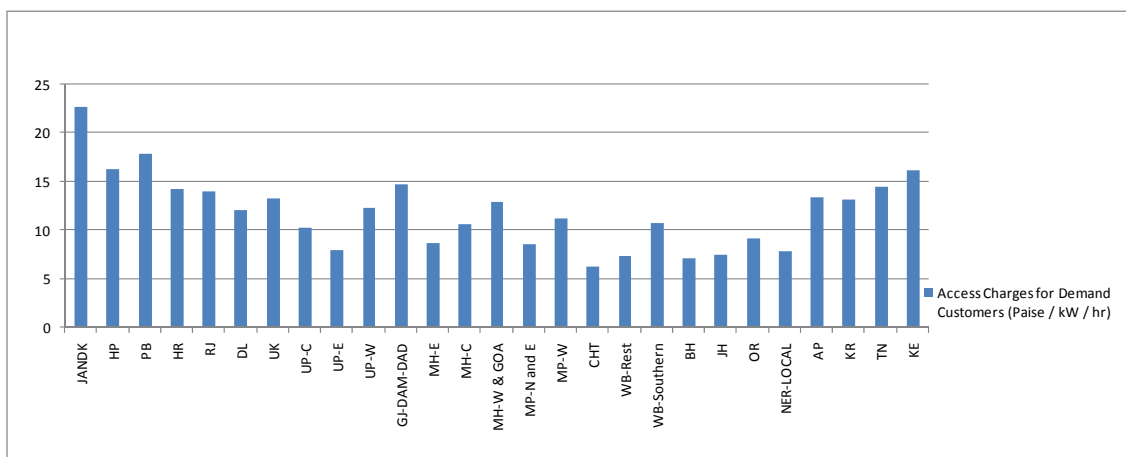
Fig. 6: Average Annual Access Charges payable by demand Customers (27 Zones)

Marginal Participation Method, as explained in the earlier sections has been used for determination of the transmission charges payable by each generator and demand customer. Therefore, each user of the transmission grid is required to pay a charge depending on its location, volume of power injected (MW), and time of use (peak and other than peak).

Box # 3: Key highlights of transmission access charges for Generators and Demand customers

Analysis of Fig. 5 reveals that the access charges in Bihar, Jharkhand and Orissa are in the same range owing to the fact that power normally flows unidirectionally from this region to NR, WR and SR. Transmission access charges for generators in NER are high because of the long transmission lines from hydro stations to the grid pooling stations (more than 100 kms and in some instances more than 200 kms).

Further, Delhi, Haryana, Punjab, UP-West exhibit transmission access charges for generators in a close range. Generation access charges in Uttarakhand are again slightly high because of long lines from the Hydro Stations.

Andhra Pradesh – North and Central, and Andhra Pradesh – Godavari region have generation, which utilizes the transmission network in normally a unidirectional manner – this leads to attribution of the charges for these lines to these generators. AP – Rayalseema, however has less generation and more load and hence a net importer– which leads to use of 'lesser' transmission network assets and hence lower transmission access charges for generators. Karnataka – West Coast region is a net power

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exporter into North and South Karnataka. This leads to higher generation access charges for generation in Karnataka – West Coast as compared to other parts of Karnataka. In Tamil Nadu, the transmission access to power plants in South Tamil Nadu (Tuticorin) is provided by long transmission lines, which leads to higher transmission access charges.

Madhya Pradesh – East is again a net exporter of electricity and this leads to utilization of the network in a unidirectional manner and hence higher transmission access charges for generators. Any generation in other parts of Madhya Pradesh, which are net importers, leads to reduction of flow on transmission network carrying power from other parts of the grid into this region. This leads to lower transmission access charges for generators in this region.

An analysis of Fig. 6 reveals that demand customers in generation heavy regions pay lower transmission access charges as compared to demand customers in load centers like Delhi, Punjab, Haryana etc. The exception here are states like Jammu and Kashmir and Himachal Pradesh, where long lines are used to access demand customers as exemplified in the box in section-4 below. The demand customers in the states in SR pay higher access charges because these states are net importers of electricity from the national grid and the demand in these states leads to a unidirectional flow of power from WR and ER. Majority of charges of the access lines into SR therefore get attributed to the demand in this region.

From a beneficiary standpoint it is essential to evaluate the total transmission charges for generation and demand related components applicable for a particular transaction. The following matrix illustrates the levels of charges that would be applicable for transactions between the various generation and demand zones.

Table 7: Average annual transmission charges for various system users

Demand Access Charge (Ps/kW/h)		22.72	16.36	17.87	14.21	13.96	12.1	13.28	10.22	7.99	12.28	14.79	8.74	10.65	12.91	8.62	11.25	6.22	7.33	10.71	7.17	7.45	9.13	7.86	13.39	13.19	14.44	16.14
Gen Access Charge (Ps/kW/h)		JANDK	HP	PB	HR	RJ	DL	UK	UP-C	UP-E	EP-W	GJ-DAM-DA	MH-E	MH-C	MH-W & GO	MP-N and B	MP-W	CHT	WB-Rest	WB-Souther	BH	JH	OR	NER-LOCAL	AP	KR	TN	KE
12.8	BH	35.52	29.16	30.67	27.01	26.76	24.9	26.08	23.02	20.79	25.08	27.59	21.54	23.45	25.71	21.42	24.05	19.02	20.13	23.51	19.97	20.25	21.93	20.66	26.19	25.99	27.24	28.94
12.46	JH	35.18	28.82	30.33	26.67	26.42	24.56	25.74	22.68	20.45	24.74	27.25	21.2	23.11	25.37	21.08	23.71	18.68	19.79	23.17	19.63	19.91	21.59	20.32	25.85	25.65	26.9	28.6
12.11	OR	34.83	28.47	29.98	26.32	26.07	24.21	25.39	22.33	20.1	24.39	26.9	20.85	22.76	25.02	20.73	23.36	18.33	19.44	22.82	19.28	19.56	21.24	19.97	25.5	25.3	26.55	28.25
14.39	WB	37.11	30.75	32.26	28.6	28.35	26.49	27.67	24.61	22.38	26.67	29.18	23.13	25.04	27.3	23.01	25.64	20.61	21.72	25.1	21.56	21.84	23.52	22.25	27.78	27.58	28.83	30.53
28.1	NER-EXP	50.82	44.46	45.97	42.31	42.06	40.2	41.38	38.32	36.09	40.38	42.89	36.84	38.75	41.01	36.72	39.35	34.32	35.43	38.81	35.27	35.55	37.23	35.96	41.49	41.29	42.54	44.24
26.92	NER-LOCAL	49.64	43.28	44.79	41.13	40.88	39.02	40.2	37.14	34.91	39.2	41.71	35.66	37.57	39.83	35.54	38.17	33.14	34.25	37.63	34.09	34.37	36.05	34.78	40.31	40.11	41.36	43.06
8.13	DL	30.85	24.49	26	22.34	22.09	20.23	21.41	18.35	16.12	20.41	22.92	16.87	18.78	21.04	16.75	19.38	14.35	15.46	18.84	15.3	15.58	17.26	15.99	21.52	21.32	22.57	24.27
9.68	HR	32.4	26.04	27.55	23.89	23.64	21.78	22.96	19.9	17.67	21.96	24.47	18.42	20.33	22.59	18.3	20.93	15.9	17.01	20.39	16.85	17.13	18.81	17.54	23.07	22.87	24.12	25.82
12.94	HP	35.66	29.3	30.81	27.15	26.9	25.04	26.22	23.16	20.93	25.22	27.73	21.68	23.59	25.85	21.56	24.19	19.16	20.27	23.65	20.11	20.39	22.07	20.8	26.33	26.13	27.38	29.08
14.72	JANDK	37.44	31.08	32.59	28.93	28.68	26.82	28	24.94	22.71	27	29.51	23.46	25.37	27.63	23.34	25.97	20.94	22.05	25.43	21.89	22.17	23.85	22.58	28.11	27.91	29.16	30.86
10.68	PB	33.4	27.04	28.55	24.89	24.64	22.78	23.96	20.9	18.67	22.96	25.47	19.42	21.33	23.59	19.3	21.93	16.9	18.01	21.39	17.85	18.13	19.81	18.54	24.07	23.87	25.12	26.82
10.69	RJ	33.41	27.05	28.56	24.9	24.65	22.79	23.97	20.91	18.68	22.97	25.48	19.43	21.34	23.6	19.31	21.94	16.91	18.02	21.4	17.86	18.14	19.82	18.55	24.08	23.88	25.13	26.83
9.69	UP-W	32.41	26.05	27.56	23.9	23.65	21.79	22.97	19.91	17.68	21.97	24.48	18.43	20.34	22.6	18.31	20.94	15.91	17.02	20.4	16.86	17.14	18.82	17.55	23.08	22.88	24.13	25.83
14.03	UP-E	36.75	30.39	31.9	28.24	27.99	26.13	27.31	24.25	22.02	26.31	28.82	22.77	24.68	26.94	22.65	25.28	20.25	21.36	24.74	21.2	21.48	23.16	21.89	27.42	27.22	28.47	30.17
14.84	UK	37.56	31.2	32.71	29.05	28.8	26.94	28.12	25.06	22.83	27.12	29.63	23.58	25.49	27.75	23.46	26.09	21.06	22.17	25.55	22.01	22.29	23.97	22.7	28.23	28.03	29.28	30.98
12.29	AP-North and Central	35.01	28.65	30.16	26.5	26.25	24.39	25.57	22.51	20.28	24.57	27.08	21.03	22.94	25.2	20.91	23.54	18.51	19.62	23	19.46	19.74	21.42	20.15	25.68	25.48	26.73	28.43
16.09	AP-Godavari	38.81	32.45	33.96	30.3	30.05	28.19	29.37	26.31	24.08	28.37	30.88	24.83	26.74	29	24.71	27.34	22.31	23.42	26.8	23.26	23.54	25.22	23.95	29.48	29.28	30.53	32.23
9.14	AP-Rayalseema	31.86	25.5	27.01	23.35	23.1	21.24	22.42	19.36	17.13	21.42	23.93	17.88	19.79	22.05	17.76	20.39	15.36	16.47	19.85	16.31	16.59	18.27	17	22.53	22.33	23.58	25.28
13.1	KE	35.82	29.46	30.97	27.31	27.06	25.2	26.38	23.32	21.09	25.38	27.89	21.84	23.75	26.01	21.72	24.35	19.32	20.43	23.81	20.27	20.55	22.23	20.96	26.49	26.29	27.54	29.24
14.79	KR-WC	37.51	31.15	32.66	29	28.75	26.89	28.07	25.01	22.78	27.07	29.58	23.53	25.44	27.7	23.41	26.04	21.01	22.12	25.5	21.96	22.24	23.92	22.65	28.18	27.98	29.23	30.93
9.25	KR-Rest	31.97	25.61	27.12	23.46	23.21	21.35	22.53	19.47	17.24	21.53	24.04	17.99	19.9	22.16	17.87	20.5	15.47	16.58	19.96	16.42	16.7	18.38	17.11	22.64	22.44	23.69	25.39
11.85	TN-North and Pondi	34.57	28.21	29.72	26.06	25.81	23.95	25.13	22.07	19.84	24.13	26.64	20.59	22.5	24.76	20.47	23.1	18.07	19.18	22.56	19.02	19.3	20.98	19.71	25.24	25.04	26.29	27.99
16.29	TN-South	39.01	32.65	34.16	30.5	30.25	28.39	29.57	26.51	24.28	28.57	31.08	25.03	26.94	29.2	24.91	27.54	22.51	23.62	27	23.46	23.74	25.42	24.15	29.68	29.48	30.73	32.43
12.32	CHT	35.04	28.68	30.19	26.53	26.28	24.42	25.6	22.54	20.31	24.6	27.11	21.06	22.97	25.23	20.94	23.57	18.54	19.65	23.03	19.49	19.77	21.45	20.18	25.71	25.51	26.76	28.46
7.42	GOA	30.14	23.78	25.29	21.63	21.38	19.52	20.7	17.64	15.41	19.7	22.21	16.16	18.07	20.33	16.04	18.67	13.64	14.75	18.13	14.59	14.87	16.55	15.28	20.81	20.61	21.86	23.56
8.67	GJ	31.39	25.03	26.54	22.88	22.63	20.77	21.95	18.89	16.66	20.95	23.46	17.41	19.32	21.58	17.29	19.92	14.89	16	19.38	15.84	16.12	17.8	16.53	22.06	21.86	23.11	24.81
16.55	GJ-Kutch	39.27	32.91	34.42	30.76	30.51	28.65	29.83	26.77	24.54	28.83	31.34	25.29	27.2	29.46	25.17	27.8	22.77	23.88	27.26	23.72	24	25.68	24.41	29.94	29.74	30.99	32.69
7.96	MH	30.68	24.32	25.83	22.17	21.92	20.06	21.24	18.18	15.95	20.24	22.75	16.7	18.61	20.87	16.58	19.21	14.18	15.29	18.67	15.13	15.41	17.09	15.82	21.35	21.15	22.4	24.1
8.65	MP	31.37	25.01	26.52	22.86	22.61	20.75	21.93	18.87	16.64	20.93	23.44	17.39	19.3	21.56	17.27	19.9	14.87	15.98	19.36	15.82	16.1	17.78	16.51	22.04	21.84	23.09	24.79
12.86	MP-E	35.58	29.22	30.73	27.07	26.82	24.96	26.14	23.08	20.85	25.14	27.65	21.6	23.51	25.77	21.48	24.11	19.08	20.19	23.57	20.03	20.31	21.99	20.72	26.25	26.05	27.3	29
	Max	50.82	44.46	45.97	42.31	42.06	40.2	41.38	38.32	36.09	40.38	42.89	36.84	38.75	41.01	36.72	39.35	34.32	35.43	38.81	35.27	35.55	37.23	35.96	41.49	41.29	42.54	44.24
	Min	30.14	23.78	25.29	21.63	21.38	19.52	20.7	17.64	15.41	19.7	22.21	16.16	18.07	20.33	16.04	18.67	13.64	14.75	18.13	14.59	14.87	16.55	15.28	20.81	20.61	21.86	23.56

Inter-regional transfers under the proposed mechanism are relatively cheaper as compared to the present mechanism. This is because the proposed transmission charges are 'point of connection' charges and avoid the problem of pancaking. This is observed for transfers from Jharkhand to Delhi which, under the proposed mechanism, will attract 24 paise / kWh as aggregate transmission charge against 32 paise / kWh that is typically incident on the average at present for such transactions. Similarly a transaction from Jharkhand to Andhra Pradesh is charged 26 paise/kWh, Jharkhand to Karnataka 25.6 paise/kWh, Jharkhand to Tamil Nadu 27 paise/kWh and from Jharkhand to Kerela 28.60 paise/kWh against the current charge in the range of 32-36 paise/kWh. Similarly a transaction from NER to Kerela would attract an aggregate transmission charge of 44 paise/kWh against current charge in the range of 48-50 paise/kWh.

Even though the matrix above indicates charges in excess of 50 ps/kw in extreme cases, from a practical transactions standpoint the charges rarely cross 45 ps/kwh even when such transactions transcend long contractual distances (e.g. NER to Punjab). In all such cases there is a strong electrical rationale for such charges based on load flows.

It needs to be noted that even as the charges have been reflected in equivalent ps/kwh to aid the understanding of the magnitude of the charges and aid comparisons with the present levels, there are two specific aspects that require mention in this context:

1. **The values indicated are essentially allocation factors (or ratios). The values would need to be scaled up or down to ensure full recovery of the ARRs of the transmission service providers on the ISTS;**

2. **The values determined would essentially be in the same ratios as the allocation factors for a given set of grid conditions for which the charges have been determined. However, the basis of charges will be Rs./MW and not ps/kwh. This is as per the current practice in the ABT regime. The MW load will be as per the capacity contracted by the generator or the demand as per the CUSA signed with the transmission service provider.**

4. ADDRESSING THE POLICY MANDATE

In designing the pricing framework it is essential to test the results for adherence to the mandate of the policy. The provisions of the National Electricity Policy and Tariff Policy have already been stated before and are not being reproduced here. The key mandates of policy relate to distance and direction sensitivity. This mandate is clearly addressed by the proposed pricing arrangements, as illustrated in the examples below.

Access charges, by virtue of being sensitive to location, are distance and direction sensitive. The distance and direction sensitivity is understood in the 'electrical sense' through the following examples:

Direction sensitivity of the transmission access charges

A generator in Delhi intending to sell power to a customer in Central Uttar Pradesh would decongest the network because the flow along this corridor is normally from the generation heavy eastern Uttar Pradesh to the load centers in and around Delhi. Such a generator would therefore be required to pay less transmission charges as compared to a generator that is located in eastern Uttar Pradesh and supplies a demand customer in Delhi. The charges are therefore direction sensitive.

Distance sensitivity of the transmission access charges

A demand customer in eastern UP pays less transmission charge as compared to a demand customer in Delhi or western Uttar Pradesh. Review of the charges reveals strong electrical rationale even in the few cases where the levels of such charges appear counter-intuitive. Two examples are provided below.

i)   Charges payable by a demand customer in Eastern Maharashtra, who contracts power from Chattisgarh pays 21 paise / kW / hr as compared to a demand customer in Western Madhya Pradesh who pays 23 paise / kW / hr. This is because Eastern Maharashtra is

The usage of the transmission network varies by season and by the time of day– peak and other than peak. The system is designed not only for peak system condition but also for peak condition on each network element. Peak condition on each network element may not coincide with the system peak. Therefore, it is paramount to consider various 'typical' conditions (snapshots) of system operation. Central Electricity Authority considers snapshots of – summer – peak and other than peak, winter – peak and other than peak, and monsoon – peak and other than peak for transmission system planning studies. The load flow analysis data provided by the Central Electricity Authority for these typical grid conditions (as they are expected in 2011-12) is used for illustrating the application of the proposed methodology on the Indian Power System. A seasonal (peak, other than peak) comparison of transmission access charges by generators and demand customers is provided in Annex 2.

5. IMPLEMENTATION OF THE PROPOSED METHODOLOGY

The methodology discussed in the preceding section provides the methodology for computing the allocation factors based on current data. In practice, the allocation factors will have to be determined from time to time as per frequency determined by CERC (this has been discussed subsequently). Based on change of network topology the zoning of the nodes would also need to be changed from time to time. Such changes of zones should not be frequent and should ordinarily coincide with the duration of tariff regulations of the CERC (five years). However it is possible that in exceptional circumstances, due to change in network topology significantly during the tariff period, re-zoning may be required earlier than anticipated. This would need to be reviewed by CERC from time to time.

Inputs to the proposed model viz., Nodal generation information, Nodal demand information, Transmission circuits between these nodes, Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch, and the associated lengths of each line will be required to be obtained systematically from each user of the network and network service provider by the NLDC (or any other agency designated by the CERC for this purpose) for computing the transmission use of the system charges for each season annually.

Nodal Generation Information

Nodal generation information will be obtained based on the generation levels committed by each generator under specific – seasonal peak and other than peak conditions identified a-priori by the NLDC. Information received by October of the year previous to the charging year will be used in the determination of the transmission use of the system charges. Based on the nodal information obtained and the computation of charges thereon as per methodology, the charges for each zone will be determined and notified by the CERC.

Nodal Demand Information

Nodal demand data will be based on demand that various beneficiary utilities (SEBs / distribution utilities) have forecast to occur at the specific peak and other than peak conditions identified by the NLDC. Information received by October of the year previous to the charging year will be used in the

determination of the transmission use of the system charges. Based on the nodal information obtained and the computation of charges thereon as per methodology, the charges for each zone will be determined and notified by the CERC.

Transmission Network Data

Transmission circuit data for charging year is to be supplied by the CTU based on transmission expansion plan data prepared in coordination with the CEA, STUs/SEBs and transmission licensees and complemented with periodic updates at frequencies to be determined by the CERC. Typically this could be undertaken at six month intervals, and will correspond to the period of resetting of the transmission tariffs. For example, if the tariffs are to be revised from April 1 and are to be valid till September 30, the network data would be obtained for this six month period by January 31.

Transmission Charge Determination

Based on the generator, demand and network related information obtained, the transmission use of the system charges are determined as Rs/MW in each season at each node would be determined based on the load flow based computational studies and application of the MP algorithms. The nodal data would be "zoned" thereafter as per the identified zonalisation criteria. Notification of the charges by the CERC would be in advance of actual implementation.

The transmission use of the system charges so determined would be fixed for each season (and peak and other than peak periods). The periodicity of revision of the charges would need to be determined based on various factors including the extent of changes in the network connections and configuration. Initially these charges could be determined every six months. The frequency may be altered later as experience is gained on the issue.

The charges applicable will be multiplied by the MW capacity contracted by each user. The capacity contracted would remain unchanged during a 6 month period at a given node. In case the contracted demand is exceeded, the actual MW recorded at the node during the month will apply.

Compensation for CTU owned, State owned assets and IPTC assets used for inter-state transfer of power

The load flow analysis, which forms the basis of the computation of the transmission charges, considers all major generation – Central Sector, State Sector and IPPs as well as the demand nodes within the state. This would continue to be the case since the Indian power system is tightly meshed, and omission of state generators, lines and demand would compromise results of the load flow analysis. Injection by state owned generation and IPPs influence the flow of power injected by the central sector generators. Therefore, in an integrated National Grid, the entire system has to perforce be modeled for load flow based price determination.

Even as the entire network is considered, the application of these charges will be restricted to the users of the IPTC. Thus, an inter-state generating station would have to pay as per the charges applicable in the zone where it is located. Similarly, the demand would be charged only to the extent of the MW contracted from the ISTS, and the charges applicable would be as per the charges of the zone from which the load is drawn. In other words, demand that interfaces with the STU system would currently not attract the charges on the same basis, unless the SERC decides to apply the same principles/basis for determining the charges for generators and loads interfacing with the state system.

Regional Load Despatch Centres would be required to maintain an account of the transmission charges to be collected from each user of the ISTS. The bills for the transmission charges for use of the ISTS would be raised by RPCs based on RLDC data. The mechanism is similar to that adopted for collection and disbursement of UI charges. As with UI, the RLDCs would however not be liable for under / delayed payment by any user of the inter-state transmission network. All the users of the inter-state transmission network will be governed by the Connection and Use of System Agreement (CUSA) a multi-party agreement, which will require grid connected entities to open an escrow with a depositary nominated for the purpose by the RLDCs of an amount based on their committed levels of chargeable capacities.

The RLDCs would compensate on a monthly basis all the transmission service providers based on their approved ARR. This would include the CTU, the IPTCs or any state owned line that predominantly features inter-state flows and is thus designated to be a part of the ISTS as per prevailing regulations. This kind of arrangement is already in place for the Tala transmission link wherein Powerlinks Ltd., the transmission asset owner, is compensated for its approved revenue requirements[2].

It is germane to note that there are currently certain lines under development where the commercial contracts are directly between the IPTCs and the beneficiaries. Such arrangements would need to undergo modification to make them consistent with the proposed framework.

Treatment of the delay in injection / withdrawal by grid connected entities

The transmission charges determined above are location specific and depend on the chargeable capacities committed by the generators / demand customers by October in the year preceding (when the Load flows are run by NLDC to determine the transmission charges) the charging year.

Connection and Use of System Agreement (CUSA) would identify the force-majeure conditions under which the delay by grid connected entities would not be charged. However, under all other conditions the charges would be paid by the grid connected entities. In case the synchronization of a generator is delayed, it will be made to bear the burden of the default in this contractual obligation. Similarly, the demand customer will bear the burden of delay in the materialization of demand. However, in case a generator is synchronised before schedule, it will be required to obtain a short term access for such period. Since as per the methodology proposed there is no distinction in charges for long term and short term open access, such access would be granted, subject to the network permitting so. The amount recovered in excess would be accounted for and the subsequent revenue requirement of the transmission service provider would be scaled down.

Treatment of the delay in creation of transmission capacity

The Transmission Utilities would be signatories to CUSA. In case of a delay (which is not due to force-majeure conditions), the transmission utility shall strive to meet all the injection and withdrawal obligations on the existing network. In the event of the transmission system not being able to meet the injection / withdrawal committed with the existing capacities, the transmission utility would be governed by the terms of the CUSA. The mechanism proposed is thus identical to the system being evolved for the IPTCs who are awarded the development rights for new assets in the system.

Mechanisms for Truing up of under / over recovery by the CTU and Transmission Licensees

Delays in implementation of transmission assets / synchronization of generating units and readiness of the distribution utilities / demand customers in off-taking electricity from the grid could lead to under / over recovery by the CTU and Transmission Licensees.

In case of any over / under recovery by the CTU and Transmission Licensees due to permissible forecasting errors by the generation / demand customers and due to reasons deemed appropriate by the CERC, the charges will be paid back / recovered from the grid connected entities through adjustments in the 'common charge'. Common charge will be shared by all the grid connected entities in proportion of the energy consumed / generated by them.

As has been mentioned elsewhere in this report, it is proposed that the process of determination of transmission charges would be conducted every 6 months based on the updated network information. This would limit forecasting issues. The period of revision can be revisited based on the experience obtained in the initial cycles of implementation.

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[2] In case of Powerlinks the CTU reimburses the revenue requirements and not the RLDC. In the proposed arrangements the revenue recovery function is proposed to be shifted to the RLDC's since the CTU is essentially one of the several transmission service providers.

6. TREATMENT OF LONG AND SHORT TERM TRANSACTIONS

The transmission use of system charges specific to each season and peak and other than peak conditions are determined for a year. The charges determined above are for specific seasonal peak and off-peak periods. These are based on load flow studies, where the generators and distribution utilities specify their generation and consumption levels respectively. The total transmission use of system charges that would accrue to generation or distribution utilities would therefore depend on the proposed values of injection or withdrawal from the grid respectively. Typically, these values in most cases would be related to the installed capacity in case of generation and to the demand proposed to be met in case of loads. To the extent such requirements are identified ahead of time, there would not be any distinction between the use of the system for long term or short term transactions. Thus the current artificial distinction between long term and short term transactions would largely be avoided.

However, in spite of the greater certainty on use of the system as compared to the present, there could still be deviations as compared to the requisitions, particularly in case of load. In case, in the real time, if injection or withdrawal is found to exceed the levels forecast by the utilities, the utilities will have to bear the additional burden of transmission charges. Any injection / withdrawal by entities entering into short term energy contract would be charged transmission charges are the rates determined by the CERC (which would be basically derived from the normal use of system charges, but, beyond acceptable tolerance levels, could include additional surcharges to disincentivise poor planning). A key benefit of the above arrangement would make the players neutral to committing in long term and short term.

A critical issue in this context is that of hierarchy of system use in case of congestion in the network. The following hierarchy is proposed:

- Long term transactions (based on PPAs) would have the highest priority, since they form the backbone of the system;

- Short term transactions would be accorded the next highest priority;

- Any over-drawal or over-injection would be accorded the lowest priority in case of congestion.

However, as the following sub-section postulates, the issue of congestion could be substantially addressed under the proposed arrangements, and hence in reality the short term transactions would stand on near equal footing with long term transactions. This would be consistent with the market development objectives.

7. ARRANGING FOR NEW TRANSMISSION CAPACITY

As the Staff Paper on "Arranging Transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity" has correctly analysed and argued, the issue of securing new capacity cannot be divorced from the pricing arrangements and the two aspects need to be considered in conjunction. Under the proposed method, the development of the transmission system would not be reliant on BPTA's with beneficiaries (since in a deep network the beneficiaries cannot arguably be identified exclusively), but would depend on the approved capital investment plans. The capital investment plans would be developed by the CTU and proposed to the CERC for approval based on the long term perspective plans and also the more immediate term plans related to generation capacity development and load growth. Once the CERC approves the plans, the lines could be built either by the CTU and/or by IPTCs, depending on the prevailing policy framework.

The CTU and IPTCs would continue to have commercial contracts (the CUSA) with the various users of the system for arranging connection to the main transmission network and for other commercial aspects including, but not limited to, payment mechanisms and security. However there would be still a fundamental shift in the approach as compared to the present wherein a line or transmission system cannot be developed till the direct beneficiaries are identified and agree to pay for the costs involved through tariffs.

It needs to be noted that while the CEA, CTU and STU will propose the system based on the expected load flows and likely generation siting, from a commercial standpoint (as well as for ensuring a fair

deal for all others who pay for the system) there could still be a need for ensuring that a generator or load pays for the system that they desire to use. Hence the CTU (or IPTCs) should be permitted to obtain the necessary security (through bank guarantees or alternate means) related to the quantum of connection (or enhancement of existing connection) desired by the user. The specific mechanisms and contents of the CUSA should be determined by the CTU and regulatory approval should be obtained for implementation.

V IMPACT ANALYSIS

Any change in framework has inevitable impact on the various users of the system. While the rationalization of charges is in line with the requirements of the law, policy and the electricity market development in general, some of the current users paying relatively lower charges would inevitably be affected while others paying irrational charges benefit. This is particularly true since the cost recovery of the transmission service providers would not change between the current and the proposed method.

Currently the charges are paid only by the beneficiaries – typically the distribution licensees. The proposed mechanisms entail all users to pay charges for use, including the generators. While this is logical from a system perspective, the change in method would require acceptance by the various users. Hence the principles need to be adequately clarified.

The above and several other issues of importance have been analysed in this section to identify in specific terms the impact of the proposed arrangements.

1. EXTENT OF ACCEPTABLE IMPACT ON SYSTEM USERS

The tariff impact on various users, and in particular the distribution licensees who presently pay the costs of transmission at present, is one of the foremost evaluation criteria for determining the acceptability of the framework proposed. Using the MP method, the average transmission charges from generator regions to load regions are reported in Table 7 earlier.

Based on the load flows and the corresponding cost computations, the maximum charge indicated at present is 50.8 ps/kwh on the average[3] for flows from NER-LOCAL to Jammu and Kashmir if such transaction were to take place. The minimum transmission charge is charged for a transaction from Goa to Chattisgarh (13.64 paise/kWh). Both these transactions are however hypothetical and realistic transactions from Uttar Pradesh-East/Bihar/Jharkhand/Orissa to Jammu and Kashmir would attract transmission charges in the range of 34-36 paise / kWh. Existing transmission charges from anywhere in the Eastern Region to Northern Region are also in the range of 32-34 paise / kWh. The efficacy of the proposed methodology is however seen from a comparison of transmission charges from Uttar Pradesh-East / Bihar/Jharkhand to Uttar Pradesh-Central / Uttar Pradesh-West/ Delhi/ Punjab/ Haryana/ Rajasthan which varies in the range of 22-32 paise / kWh. This clearly exhibits the distance sensitivity of the proposed mechanism. An analysis of contracts from generators near load centers to demand customers near generation hubs reveals the direction sensitivity of the proposed mechanism.

Intra-regional transaction from Chattisgarh to Maharashtra-East involves total transmission access charges of 21 ps/kWh against current transmission tariffs in the range of 16-17 paise / kW / hr. Similarly intraregional transactions from West Bengal to Bihar would require the transmission demand customers to pay and aggregate of 21.56 paise / kWh (as compared to 16-17 paise / kWh). In Southern Region, a contract between demand customers in Andhra Pradesh and Generators in AP-Rayalseema zone would require 22.53 paise/kW/hr to be paid as access charges (as compared to 16-17 paise / kWh). Contract with generators in AP-North and Central AP-Godavari would require a total transmission charge of 25 paise/kWh and 29 paise/kWh respectively. The higher transmission access charges are due to higher charges attributable to generators in AP-Godavari because of long transmission lines (more than 100 kms) from hydro power stations. In Kerela, the charges are high because of the transmission charges for demand customers – which are high due to the state being a net importer.

Inter-regional transfers under the proposed mechanism are relatively cheaper as compared to the present mechanism. This is because the proposed transmission charges are 'point of connection'

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[3] The per kwh rate has been shown to illustrate the effective charges, In practice the transmission tariffs will be in Rs./MW/month as per the current practice. The key difference will be in the fact that generators will pay for the MW evacuation capacity contracted for injection at their location while loads will pay for the MW capacity contracted for offtake.

charges and avoid the problem of pancaking. This is observed for transfers from Jharkhand to Delhi which, under the proposed mechanism, will attract 24 paise / kWh as aggregate transmission charge against 32 paise / kWh currently being charged. Similarly a transaction from Jharkhand to Andhra Pradesh is charged 26 paise/kWh, Jharkhand to Karnataka 25.6 paise/kWh, Jharkhand to Tamil Nadu 27 paise/kWh and from Jharkhand to Kerela 28.60 paise/kWh against the current charge in the range of 32-36 paise/kWh. Similarly a transaction from NER to Kerela would attract an aggregate transmission charge of 44 paise/kWh against current charge in the range of 48-50 paise/kWh.

Intra state transactions invite higher transmission access charges in states where high voltage long AC transmission lines emanate, viz., Jammu and Kashmir, Arunachal Pradesh, Assam, Manipur, Nagaland and Tripura. There is an economic and technical rationale for this result. The levels of generation in these states are relatively low and this power is transmitted over HVAC lines, where the flow is largely unidirectional from NER to ER. This leads to higher charge per MW attributable to the generators in these states. Further, the demand in these states seems to be largely served by high voltage radial lines. This leads to a high access charges in these regions. However arguments based on environmental and social concerns could call for socialization of high access charges in these states. Most of the power generated in these states is from hydro resources, which are environmentally beneficial and have a positive global externality. The excess of any access charges for such generators (or a percentage, as determined by the regulator) over and above the "reasonable" levels can therefore be allocated to all the network users based on a postage stamp mechanism. However, it needs to be noted that while the charges for such generation is relatively higher, there is a sharp reduction as compared to the regional postage stamp based method. It needs to be noted in this context that the transmission service providers would fully recover their revenue requirements even if there is a reduction in the charges paid by the remote generators. As also mentioned earlier, given the electrical similarity which is also reflected in low intra-regional variance in access charges in NER, it might be prudent to aggregate the NER states and determine a single generation access and a demand access charge for these regions. Similarly small states like Pondicherry have been combined with Tamil Nadu – North, and Dadra and Daman have been combined with the neighbouring Gujarat region.

2. IMPACT ON SPECIFIC SYSTEM USERS

Impact on Generators – Long Term contracts

Under long term energy purchase agreements, the fixed charges of the generators are shared by the beneficiaries in proportion of their commitment in the plant capacity. The transmission charges, determined above add to the fixed charge component of the generator. The dispatch in the energy markets does not get affected because the variable charges of the generators remain unaltered.

Transmission Network Use of System Charges for each generator is different for each season. The charges payable for each generator are determined as a product of Power Station forecast Chargeable Capacity (in MW) multiplied by the zonal Rs/MW/hr tariff determined above. The total seasonal transmission use of the system charges are determined by further multiplying the above product by the number of hours in the season – for peak and other than peak periods. This seasonal Transmission Network Use of System charge is split evenly over the months of the season (for peak and other than peak periods) and charged on a monthly basis over the season.

If the actual generation increases above the forecast for the charging season, the party will be liable for the additional charge incurred for the full season, which will be recovered uniformly across the remaining chargeable months in the relevant charging season. In case the generation is in excess of the contracted transmission capacity, the billing would be as per actual recorded generation levels during the month. However, any excess injection vis-à-vis capacity would need to be within acceptable levels. In event of the generation being significantly higher than the access capacity contracted (either on short term or long term basis), penal charges may need to be applied. No recalculation is to be done in the cases where the generation is below the forecast generation level.

Impact on the customers (beneficiaries): Distribution Utilities – Long Term Contracts

Currently, the customers of long term power are required to pay transmission charges based on the contract path expected to be traversed by power from the point of injection to the point of withdrawal. Therefore, if the power is injected in NER and withdrawn in NR, the beneficiary in the NR will be required to pay as transmission charges the sum of regional postage stamp charges of NER, ER and NR and also the charges for inter-regional linkages. Under the proposed mechanism, the beneficiary will have to pay the transmission use of the system charges for demand directly. Indirectly, the transmission use of the system charges for the contracted generator is also paid by the beneficiary through the fixed charge component of the generator's charge. Therefore, the total burden of transmission tariff on the beneficiary distribution utility will be the sum of the generator's charge (charged through the fixed charge of the generator) and the transmission charge paid directly by the beneficiary.

Throughout the season Users' monthly demand charges will be based on their forecasts of demand to be supplied, multiplied by the relevant zonal Rs/MW tariff. The beneficiary's seasonal Transmission Network Use of System demand charges will be based on these forecasts and are split evenly over the months of the season. Users have the opportunity to vary their demand forecasts on a seasonal basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. The beneficiary utilities will be notified of the timescales and process for each of the seasonal updates. CTU would revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months.

The beneficiary utilities are expected to submit reasonable demand forecasts. The CTU would need to use a methodology approved by the concerned state regulatory commission to derive a forecast to be used in determining whether a beneficiary's forecast is reasonable and this will be used as a replacement forecast if the beneficiary's total forecast is deemed unreasonable. The CTU would have to use the latest available settlement data for this purpose.

Impact on the customers (beneficiaries) within the same region as generation – Long Term Contracts

There could be a particular concern of beneficiaries located within a region on the high charges incident even for consumption in proximity to generation. In particular, the distribution utilities in the North East could be affected due to the high generation costs component which such beneficiaries would have to bear. Several relevant factors need to be noted in this context. Firstly, the allocations (except for free power) from the large projects being developed in the North East for constituents in the region are low. Secondly, the component attributable to licensees for transacting energy is low, but the generation related component (that the licensee has to eventually bear) is high. There is a strong technical justification for the high generation related component. However, if there is any residual concern regarding charges applicable when the generation and consumption is in the same region, socialization criteria can be applied to limit the charges to an "acceptable" level. Such levels would be up to regulatory judgment, and the residual amounts after applying these limits would need to be distributed over other users. However, based on review of the data, this does not appear to be a significant issue in any electrical region other than the North East. Even if such limits were to be hypothetically applied for licensees in the North East, the impact on other system users would be minimal on account of the low consumption levels in the North East from the ISTS.

Impact on Generators – Short term Bilateral contract

In short term bilateral energy markets, generators negotiate a lump-sum price per kWh with the buyer / trader. The negotiated price so determined is normally expected to include both the fixed charge component and the variable component of generation charge. The fixed charge of the generator would include the locational component of the transmission charge. It has been argued that this distorts the price signals of electrical energy in the short term market.

However, another view is that by including the signals of utilization of transmission assets in their bid, the generators, in the short term markets send signals for capacity expansion. Power is normally contracted in short term markets to satisfy the 'unanticipated' needs of the customer. The power system, therefore, operates close to its capacity limits in the short term markets. The price signal should therefore reflect the long run marginal cost of system usage under such conditions for allocative efficiency. The inclusion of access charges for transmission in the negotiated prices would therefore send the correct signal.

Impact on customers (beneficiaries): Distribution Companies – Short term Bilateral Contracts

For accessing the grid for capacity which is required in the short term, the load will need an approval of the same from SLDC and RLDC. Then beneficiary utility / load will pay the locational transmission charges applicable. The transmission access charges of the generators are paid indirectly as discussed in the section above.

The short-term chargeable capacity for demand is any approved demand level applicable to that beneficiary during a valid short term period. Such demand level will need to be approved by the appropriate SLDC / RLDC for a given period. The charges in Rs/kW are the same as those applicable to approved forecast seasonal. In case a beneficiary seeks approval for a short term chargeable demand for more than a month in a season, the revised higher level of chargeable demand shall be deemed to be the long term chargeable demand and the seasonal charges will be recalculated on the basis of the revised chargeable demand.

Impact on trades through Power Exchange

The generators that are dispatched through the power exchange shall internalize the transmission access charges in their price bids according to its location. This would be different from the earlier system in which a fixed transmission charge was required to be paid irrespective of location. The transmission access charges will be deemed to be included in the price bid on the exchange since both the buyer and seller would have to pay for the Transmission Network Use of System Charges as per the CERC regulations.

3. IMPACT ON NETWORK DEVELOPMENT

The proposed mechanism requires the grid connected entities viz., the generators and the demand customers (distribution utilities, large customers) to pay transmission access charges based on their location and forecasted chargeable capacity / demand. This mechanism is true to the physics of power flow because in a large grid, given the network topology and injection / withdrawal by other grid connected entities, an increase in injection / withdrawal by an agent at a particular node causes changes in flows on various lines in a similar manner irrespective of the commercial contract driving the transaction. Thus, a generator must pay transmission access charge attributable to it and demand must pay the locational access charge attributable to it. This obviates the need for Bulk Power Transmission Agreements as required by the National Power Policy. For the purposes of transmission planning the generator / demand customer may just specify the maximum injection / withdrawal from the grid under specified seasonal peak / off-peak periods. Given these injection / withdrawal needs, the CEA, CTU and STUs can then perform national transmission planning and capacity expansion in the most cost effective manner and in a manner that minimizes network congestion.

The proposed mechanism, as shown above, provides very strong locational signals for siting of generation and demand from a transmission cost perspective. Any increase in demand in NER should ideally be driven by low transmission charges for demand customers. This would trigger more use of the transmission system in NER and the costs of the same would then be borne by the generators and demand customers there. This would lead to a decrease in transmission access charges for generators. The importance of separate locational signals for generation and load is discussed in section II - 3 (c).

Though the locational transmission access charges lead to allocative efficiency and are cost-reflective, the transmission access charges so determined can cause equity concerns. The socialization of such charges can be done using the concepts of cooperative game theory. In the literature on allocation of joint costs approaches based of Shapley values, Nucleolus and min-max fairness criteria have proposed in the context of allocation of transmission charges. The concept of Nucleolus as proposed by Schmeidler has its analogy in the welfare economic literature, in which J. Rawls proposed a welfare criterion that often is offered as an alternative to the Pareto criterion. The Pareto criterion requires that any individual's utility function be maximized subject to the constraint that no other individual's utility be decreased. Rawls' criterion requires that the utility function of the least well-off person be maximized. The concepts of Nucleolus and min-max fairness criteria are based on minimizing the

maximum transmission access charge. This is equivalent to minimizing the maximum objection by any state or a group of states.

Adjustments based on the above criteria can be considered based on the view of the CERC and other stakeholders on the tradeoff between efficiency and cost-reflectiveness on one hand and equity on the other. Even after adjustments in the interest of equity are made, the locational transmission access charges would still obviate the need for Bulk Power Transmission Agreements.

4. IMPACT ON LOW CARBON GENERATORS

The key low carbon generators in the Indian power system are the hydro and wind resources. The option for treatment of charges for hydro in the North East has already been discussed earlier in this paper, along with the approach for "socialization" of such costs in case this is deemed to be a policy objective. If the generation access charges by hydro generators in NER were to be reduced to 25 paise / kW / hr (as compared to 28.1 ps kW / hr), the additional burden on the grid connected entities (generators and demand customers) would be 0.05 paise / kW / hr. Thus, it may be necessary and indeed worthwhile to reduce the access charges for generators in NER by a small but meaningful amount that encourages more generation capacity in the region and makes market access more attractive (without altering Locational signals significantly) since the impact on the rest of the system users is negligible. Such mechanisms could be extended to hydro resource rich states to provide impetus to hydro generation. This would address one of the requirements of the National Electricity Policy which places priority in harnessing of the hydro resources of the country.

The issues in wind are distinct from that of hydro. Typically wind resources are "embedded" in the state systems. Embedded generators would benefit from the proposed transmission charging methodology through better market access if the proposed mechanism is applied at the state level. Marginal Participation based pricing mechanism would greatly facilitate transactions from such resources, if such generators seek to access the ISTS for open access and trading. This is because the incidence of pancaking would be significantly reduced. However such generators would have to book transmission capacity on the ISTS and pay for the same at par with other generators (in addition to the charges attracted for use of the state level transmission system). In particular where wind resources are located close to load centers, they would be charged a low access charge because these power plants obviate the need for investment in transmission system. In addition, if felt appropriate, the transmission charges applicable to renewable energy sources located away from the load centers may also be capped at an appropriate level and the shortfall in the revenue of the transmission service provider could be made up in the same manner as indicated above for hydro power projects.

VI IMPLEMENTATION PROCESS AND WAY FORWARD

1. CHANGES IN COMMERCIAL SYSTEMS AND PROCESSES

Implementation of the proposed framework is expected to be relatively straightforward. The key inputs for implementation are stated below:

1. Revenue requirements of transmission services providers for the various lines, sub-stations or projects;

2. Load flow analysis for various seasons based on user inputs for generation and demand

3. Appropriate metering systems

4. Billing, collection and revenue distribution mechanisms

The first aspect is already determined by the CERC as per its tariff regulations. This process will remain unchanged, and the cost recovery requirements of CERC for the various projects will be aggregated. Such aggregated revenue requirements will be utilized to obtain the transmission rates per MW at the various generation or load buses (or zones).

The load flows are a critical input for determining the allocation factors and charges. As mentioned earlier in this paper, the generators and licensees (or other users) would have to specify their requirements in advance prior to the implementation period. The CEA, CTU or any other agency nominated for this purpose would conduct load flows and determine the allocation factors. The forecasting capabilities of the users could need attention to ensure that the requisitions provided for conducting the load flows and for commercial transactions are representative.

The metering systems will remain unchanged since the tariff structure will be identical to those at present (Rs. per MW per month). While there could be an element of seasonality in the tariffs, the existing SEM based metering system would be adequate for such purposes. Since the meters are already equipped with demand registers, deviations from requisitioned/contracted demand would be captured by the meters.

The billing systems could require minor changes to accommodate the seasonality requirements (if required) and over-drawal vis a vis requisitions/contracts. The billing will continue to be done by the RPCs on monthly basis as at present.

The current mechanisms for payment security that the CTU has in place for distribution licensees will continue. However for generators, suitable commercial arrangements would need to be implemented. In case of long term contracts, beneficiaries may elect to continue the existing system where they are liable for the entire transmission charges and related commercial arrangements. In particular, the existing arrangements that are already in place for long term contracts/BPTAs could be continued.

2. CHANGES TO REGULATIONS

Changes are envisaged in the Open Access regulations of CERC on account of the fundamental alterations in the principles of short term open access and pricing thereof. Specific changes required would be identified separately after the finalization of the approach proposed.

The tariff regulations of CERC currently in place would need to be supplemented to reflect the changed procedure for charges for use of the ISTS. This process would follow the finalization of the framework proposed for implementation consequent to the consultation process on this discussion paper.

A key issue for consideration is the basis for allocation of losses to various users. As mentioned, CERC has already mandated IIT Mumbai to undertake a study for the same based on the "power tracing" method. The results of the same, once available, would need to be reflected in the respective regulations.

VII ANNEXES

ANNEX 1: CREATION OF GENERATION AND DEMAND ZONES

Jammu and Kashmir

A generation bus-wise comparison of the state indicates that the impact of generation at various generation buses (12 buses) on the national grid and hence the transmission access charges vary in a close range in each season. The annual average transmission access charge for generators in Jammu and Kashmir is 14.72 paise / kW / hr.

All the generation buses in Jammu and Kashmir are therefore combined to form one generation zone.

Similarly, all the demand buses in the states are combined to form a single zone because of very low variance in transmission access charges for various nodes.

Himachal Pradesh

All the buses (17 buses) have been combined into one zone because the access charges vary in a close range except Chamera. Access charges for Chamera too has been clubbed with those of other nodes in Himachal Pradesh and average annual access charge for generators in the state is 12.94 paise / kW / hr.

All the demand buses in the states are combined to form a single zone because of very low variance in transmission access charges for various nodes.

Punjab

All the buses (11 buses) have been combined into one zone because the access charges vary in a close range. The annual average generation access charge for the state is 10.68 paise / kW / hr.

All the demand buses in the states are combined to form a single zone because of very low variance in transmission access charges for various nodes.

Haryana

All the buses (8 buses) have been combined into one zone because the access charges vary in a close range. The annual average access charge for generators in the state is 9.68 paise / kW / hr.

All the demand buses in the states are combined to form a single zone because of very low variance in transmission access charges for various nodes.

Rajasthan

All the buses (17 buses) have been combined into one zone because the access charges vary in a close range. The annual average access charge for generators in the state is 10.69 paise / kW / hr.

All the demand buses in the states are combined to form a single zone. The ISTS has a thin network in Rajasthan and no significant differentiation was found between transmission access charges at various nodes.

Uttaranchal

All the buses (14 buses) have been combined into one zone because the access charges vary in a close range. The annual average access charge for generators in the state is 14.84 paise / kW / hr.

All the demand buses in the states are combined to form a single zone because of very low variance in transmission access charges for various nodes.

Delhi

All the buses (5 buses) have been combined into one zone because the access charges vary in a close range. The annual average access charge for generators in the state is 8.13 paise / kW / hr.

All the demand buses in the states are combined to form a single zone because of very low variance in transmission access charges for various nodes.

Uttar Pradesh

Uttar Pradesh has been divided into two generation zones – East Uttar Pradesh (UP-E) (15 buses) and West Uttar Pradesh (UP-W) (10 buses). While East Uttar Pradesh is predominantly a generation hub, west Uttar Pradesh is a load centre with some generation. The network access charges for generators in UP-E vary in a very close range and the average annual access charge for generators is 14.03 paise / kW / hr. This is similar to the access charge for generators in Jammu and Kashmir (14.72 paise / kW / hr). The generators in West Uttar Pradesh, however can access the network at 9.69 paise / kW/hr). This is comparable to the access charge for generators in Delhi (8.13 paise / kW / hr. The proposed tariff mechanism, therefore gives a very strong locational signal – based on the expected electrical distance and direction of flow of electricity.

Uttar Pradesh has been divided into three demand zones – East, Central and West. As expected, the transmission access charges for demand customers are the lowest in UP-East and increase as one moves towards UP-West. The transmission access charges for demand customers in UP-West are similar to those in Delhi.

Goa

All the buses (2 buses) have been combined into one zone because the access charges vary in a close range. The annual average access charge for generators in the state is 8.13 paise / kW / hr.

Goa has been clubbed with Maharashtra-West because of similarity in transmission access charges for demand customers.

Gujarat

Gujarat has been bifurcated into Gujarat zone and Gujarat-Kutch zone. The average annual generation access charge for Gujarat zone is 8.67 paise / kW / hr. A comparison of this charge with generator access charge in Delhi (8.13 paise / kW/hr) further indicates the locational signal provided to generators located close to load centers.

The generator access charge for Gujarat-Kutch zone is 16.55 paise / kW / hr. This is due to the long lines connecting generators in Kutch region (3 buses) with the main grid.

The demand charges in Kutch and Saurashtra regions of Gujarat were higher than those in Western Gujarat. This is however due to thin penetration of ISTS network in that region. Therefore, these two

regions were clubbed with Eastern Gujarat and for purposes of determination of transmission access charges for demand customers, Gujarat has been considered as a single zone.

Maharashtra

In spite of being a large state the presence of 400 kV ring around Maharashtra lends considerable uniformity in the manner in which generators located both in the east and west parts of the state use the grid. This is reflected in the very narrow range in which generator access charges vary. The state has therefore been considered as a single zone for generators. The average annual transmission access charge for generators in the state is 7.96 paise / kW / hr.

Perceptible difference in transmission access charges was found in the case of Maharashtra between East, Central and West Maharashtra, the highest charges being in East Maharashtra which gradually reduce as one moves towards West Maharashtra.

Madhya Pradesh

In Madhya Pradesh electricity normally flows from east to west. This is reflected in higher access charges for generators in Vindhyachal, Amarkantak etc. Madhya Pradesh has therefore been bifurcated into two zones – MP-East and MP. The average annual transmission access charge for generators in MP-East is 12.86 paise / kW / hr, whereas the transmission access charge in other parts of MP is 8.65 paise / kW / hr.

Madhya Pradesh has been bifurcated into two demand zones – North and Central and West. The North and Central Madhya Pradesh being generation hubs, the demand customers are burdened with less transmission access charges in this region as compared to West Madhya Pradesh.

Chattisgarh

The generators in Chattisgarh exhibit uniformity in the manner in which they utilize the grid. The average annual transmission access charge for generators in Chattisgarh is 12.32 paise / kW /hr. Again, this compares closely with east Madhya Pradesh (12.86 paise/kW/hr), which is also a part of the belt from where electricity is normally exported to other states.

Chattisgarh has been considered as a single zone for the purposes of access by demand customers because of lack of differentiation in access charges between various nodes.

Bihar

The generators in Bihar too utilize the electricity network in a similar manner. This similarity in the utilization of the network is reflected not only for generators within Bihar but also with other states (which are electrically similarly placed), like Chattisgarh and Jharkhand. The average annual transmission access charge for generators in Bihar is 12.80 paise / kW /hr.

Bihar has been considered as a single zone for the purposes of access by demand customers because of lack of differentiation in access charges between various nodes. The outliers in Bihar were however, Gopalganj, Saharsa and Darbhanga because of long lines into these regions. These have been excluded in the computations.

Jharkhand

All the buses in Jharkhand exhibit network utilization in a similar manner. The average annual transmission access charge for the state is 12.46 paise / kW / hr.

Jharkhand has been considered as a single zone for the purposes of access by demand customers because of lack of differentiation in access charges between various nodes.

West Bengal

All the buses have been combined into one zone because the access charges vary in a close range. The annual average access charge for generators in the state is 14.39 paise / kW / hr. Since most of the power generated here flows into the Northern Region, through Bihar – the network access charges are slightly higher than those in Bihar / Jharkhand.

West Bengal has been bifurcated into two zones – Southern Bengal and Rest of Bengal for the purposes of access by demand customers. The charges in Rest of Bengal are lower than those in Southern Bengal due to proximity to generation sources.

Orissa

The average annual transmission access charge for generators in Orissa is 12.11 paise / kW / hr – similar to those in Bihar / Jharkhand / Chattisgarh. Outliers in South Orissa have higher charges due to long radial lines, but have no relevance for the present exercise since there is no future generation that can connect on the ISTS is proposed in that area. Hence these outliers have not been considered.

Orissa has been considered as a single zone for the purposes of access by demand customers because of lack of differentiation in access charges between various nodes.

North Eastern Region (NER-EXP, NER-Local)

Generators in Arunachal Pradesh, Assam, Manipur, Meghalaya, Mizoram, Nagaland, Sikkim and Tripura have been combined into NER-Local and NER-Export zone. The power generated by generators in the export zone is essentially meant to be carried into other regions. All the power plants in Sikkim, Bhutan (Tala, Chukha), Subansiri (Assam), Arunachal Pradesh, Tripura are assumed to be in NER-EXP zone and the others are assumed to be in NER-Local. The average annual transmission charge applicable to generators in NER-EXP and NER-Local is 28.10 paise / kW / hr and 26.92 paise / kW / hr respectively.

NER-LOCAL has been considered as one demand zone comprising of all the states in NER. The access charges for demand customers vary in a narrow range in NER.

Andhra Pradesh

For Generation, Andhra Pradesh has been trifurcated into three zones – North and Central, Godavari and Rayalseema for the purposes of access by generators. This is based on the line configurations and resultant load flows. For example, north and central coastal Andhra Pradesh (referred to as Godavari) has substantial coal and gas based generation that is relatively far from the main load centres, and hence the charges for the area are relatively higher. The phenomenon is reversed in Southern Andhra Pradesh.

Andhra Pradesh has been considered as one demand zone. The state has deep ISTS network and has also been an importer and likely to remain so till the end of the XI plan. Flows are indicated to be unidirectional from WR and ER into SR. As a result, zoning of AP did not yield any significant differentiation in transmission access charges by demand customers.

Karnataka

Karnataka has been bifurcated into West Coast and Rest of Karnataka. Coastal Karnataka has substantial hydro and nuclear generation that is relatively far from the main load centres, and hence the charges for the area are relatively higher.

Karnataka has been considered as one demand zone. Karnataka has a deep ISTS network. Karnataka has also been an importer and likely to remain so till the end of the XI plan. Flows are indicated to be unidirectional from WR and ER into SR. As a result, zoning of Karnataka did not yield any significant differentiation in transmission access charges by demand customers.

Tamil Nadu

Tamil Nadu has been bifurcated into two zones – TN (North and Pondicherry), TN (South). The Southern part of the state (including the Tuticorin and Koodankulam complexes) is far from the demand, and thus attracts higher charges based on network use.

Tamil Nadu has been considered as one demand zone. Tamil Nadu has a deep ISTS network. Tamil Nadu has also been an importer and likely to remain so till the end of the XI plan. Flows are indicated to be unidirectional from WR and ER into SR. As a result, zoning of Tamil Nadu did not yield any significant differentiation in transmission access charges by demand customers.

Kerala

Kerala has been considered as a single zone for the purposes of access by generators and demand customers based on the electrical parameters of the system, which indicates homogeneous charges.

ANNEX 2: SEASONAL VARIATIONS IN TRANSMISSION CHARGES UNDER THE MARGINAL PARTICIPATION METHOD

Table A1: Transmission Access Charges payable by Generators in various seasons (Peak and Other than Peak periods) (in Paise / kW/hr)

Generator Zones	Sum-Peak	Mon-Peak	Win-Peak	Sum-OTP	Mon-OTP	Win-OTP	AV-Annual
BH	16.27	14.49	14.07	10.64	10.85	10.75	12.80
JH	15.27	13.45	13.47	11.21	11.02	11.37	12.46
OR	14.40	11.10	14.16	11.09	10.50	11.32	12.11
WB	18.07	15.30	15.97	12.88	12.54	13.10	14.39
NER-EXP	30.01	31.73	25.72	27.64	29.46	22.90	28.10
NER-LOCAL	27.47	30.17	23.08	27.38	29.05	21.89	26.92
DL	10.89	11.40	8.46	6.73	7.22	6.92	8.13
HR	12.83	13.55	10.04	8.18	8.41	8.09	9.68
HP	16.72	18.18	12.64	10.24	10.46	10.13	12.94
JANDK	17.44	18.82	14.79	12.69	13.70	13.38	14.72
PB	14.43	15.21	10.94	8.76	8.84	8.52	10.68
RJ	11.54	12.60	9.59	9.89	10.75	10.58	10.69
UP-W	12.49	13.09	9.80	7.95	8.46	8.17	9.69
UP-E	16.35	16.33	14.49	13.08	13.10	12.81	14.03
UK	17.40	19.45	14.61	10.96	13.01	13.56	14.84
AP-North and Central	11.49	10.67	13.28	12.85	12.20	12.79	12.29
AP-Godavari	15.72	15.42	17.49	16.41	15.45	16.15	16.09
AP-Rayalseema	8.91	9.12	10.54	8.96	8.35	8.92	9.14
KE	12.95	12.71	14.79	13.11	12.37	13.02	13.10
KR-WC	12.51	12.15	13.75	16.03	15.52	16.05	14.79
KR-Rest	8.54	7.50	9.42	9.94	9.48	9.96	9.25
TN-North and Pondi	10.41	10.77	12.54	12.50	11.75	12.42	11.85
TN-South	16.15	14.95	18.49	16.34	15.59	16.24	16.29
CHT	13.19	10.97	13.18	12.14	12.07	12.38	12.32
GOA	6.79	5.49	7.81	7.91	7.58	7.88	7.42
GJ	8.26	7.17	8.18	9.04	9.15	9.25	8.67
GJ-Kutch	13.01	14.31	12.39	17.80	18.40	18.40	16.55
MH	7.39	6.31	7.85	8.42	8.25	8.49	7.96
MP	9.36	8.12	9.04	8.38	8.45	8.62	8.65
MP-E	13.25	12.08	13.30	12.70	12.83	12.99	12.86

Fig A1: A graphic representation of the seasonal and time of day variation in transmission access charges for generators (in Paise /kW/hr)
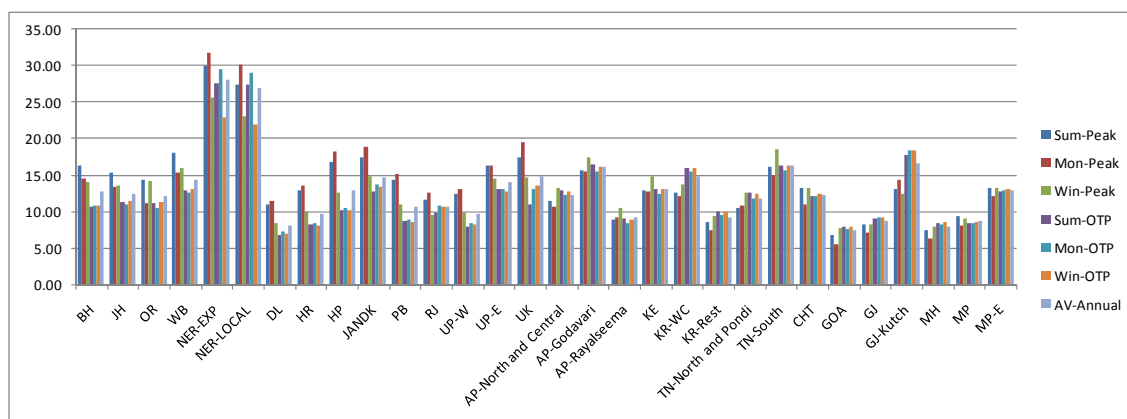
Table A2: Transmission Access Charges payable by demand customers in various seasons (Peak and Other than Peak periods) (in Paise / kW / hr)

Demand Zones	Sum-Peak	Mon-Peak	Win-Peak	Sum-OTP	Mon-OTP	Win-OTP	AV-Annual
JandK	22.32	18.06	23.69	23.14	23.51	23.99	22.72
HP	13.70	11.63	16.60	16.86	18.20	18.62	16.36
PB	15.50	13.62	18.21	18.31	19.46	19.89	17.87
HR	12.45	11.18	14.30	14.36	15.48	15.91	14.21
RJ	14.58	13.89	15.04	13.76	13.39	13.62	13.96
DL	10.60	9.32	12.32	12.27	13.11	13.56	12.10
UK	11.05	9.85	13.17	13.72	14.69	15.14	13.28
UP-C	9.54	8.86	10.72	10.24	10.45	10.99	10.22
UP-E	6.96	6.75	8.11	8.16	8.42	8.79	7.99
UP-W	10.86	9.88	12.39	12.42	13.20	13.68	12.28
GJ-DAM-DAD	17.37	17.91	16.41	13.28	13.31	12.85	14.79
MH-E	10.21	10.93	9.00	8.01	8.14	7.47	8.74
MH-C	12.78	13.43	11.33	9.48	9.69	9.04	10.65
MH-W and Goa	15.23	15.97	13.48	11.66	11.89	11.19	12.91
MP-North and East	9.37	9.41	9.41	8.25	8.14	7.88	8.62
MP-West	12.68	12.84	12.17	10.53	10.45	10.10	11.25
CH	7.53	8.16	6.73	5.61	5.62	4.93	6.22
WB-ROB	6.53	8.00	6.60	7.11	7.87	7.68	7.33
WB-Southern	11.16	13.91	10.73	9.60	10.21	9.95	10.71
BH	6.13	6.35	6.65	7.50	7.69	7.93	7.17
JH	7.46	8.64	7.10	6.64	8.51	6.68	7.45
OR	10.32	11.13	9.16	8.33	8.85	8.05	9.13
NER-LOCAL	6.85	7.43	7.79	7.18	7.53	9.88	7.86
AP	16.55	15.60	12.83	12.34	12.74	11.82	13.39
KR	16.11	15.46	13.06	12.08	12.54	11.57	13.19
TN-PONDI	19.21	16.66	14.65	12.84	13.26	12.28	14.44
KE	19.75	18.18	15.72	14.99	15.43	14.45	16.14

Fig A2: A graphic representation of the seasonal and time of day variation in transmission access charges for demand customers (in Paise / kWh)