Explanatory Memorandum on the Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Loss) Regulations, 2010

A. Background

1. The genesis of the revised framework for sharing of transmission charges and losses lies in the National Electricity Policy (NEP), which mandates that the national tariff framework implemented should be sensitive to distance, direction and related to quantum of power flow. Further, the Tariff Policy requires that transmission charges, under these broad guidelines, 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 (Designated ISTS Customers, DICs) 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. Also 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 take up the execution after due regulatory approvals. On the allocation of losses, Tariff Policy requires that transactions should be charged on the basis of average losses arrived at after appropriately considering the distance and directional sensitivity on the transmission system.
2. The sharing of transmission charges and transmission losses is presently being done on the basis of Regional Postage Stamp Method, i.e. all States in the Region are sharing the transmission charges and transmission losses on a Regional pooled basis, in the ratio of the quantum of power drawn through the Inter-State transmission system. The quantum of power drawn is calculated as the sum of entitlements (firm share plus share from unallocated quota of power in the Central Generating Stations) from Central Generating Stations and long-term contracts between sellers (which could be surplus States or IPPs) and buyers (which would normally always be States). Therefore, a State in Southern Region buying power from a State in Eastern Region would have to pay for the pooled transmission charges and transmission losses of Eastern Region and Southern Region. Further, many new IPPs are expected to come up in the near future and with bulk consumers also being allowed to purchase power through open access from anywhere in India, even across Regions. The mechanism has served the needs of the system well. However, with the integration of the regional grids, and the objective of the policy and regulatory framework to provide access to sellers and buyers, a appropriate change in the pricing mechanism is required.
3. Under the current mechanism, transfer of power from any state, e.g Chattisgarh in WR to Punjab in NR, requires the transacting parties to pay a sum of transmission charges in both these regions – a phenomenon referred to as “pancaking” of charges. This makes such transactions artificially expensive and hence less competitive and non-reflective of the network utilization. Further, an ideal transmission pricing mechanism should allow the power plant developers and customers to decide the optimal location of the power plant by comparing the costs of fuel transportation and the cost of electricity transmission. The present transmission pricing mechanism based on ‘regional postage stamp’ needs to be revised to suit the needs of the changes in the market structure and the policy framework.
4. The staff of CERC circulated the approach paper on “Formulation of Inter-State Transmission pricing Mechanism” on May 15 2009 for public comments. This was followed by workshops held by CERC in Delhi, Kolkata, Guwahati and Bangalore to explain the proposed transmission pricing mechanism to various constituents. This was followed up by a public hearing.

5. The CERC, after due consideration of the alternative methodologies for allocation of transmission charges and the comments received from various stakeholders has considered implementation of the Point of Connection (PoC) methodology based on a hybrid method, which brings together the strengths of both the Marginal Participation and the Average Participation Method discussed in the staff paper. Under this framework, any generator node is required to pay a single charge based on its location in the grid to gain access to any demand customer located anywhere in the country. Similarly, any demand node will also be required to pay just one charge and get access to any generator in the grid. This is based on load flow studies conducted for each node, one at a time. The same principle holds for transmission losses that a generator node or demand node has to bear.

6. The PoC based transmission mechanism will benefit the transmission network development and the DICs of the transmission system in the following ways:

   - At present the transmission investments are faced with the uncertainty in generation and also the cumbersome process of getting the Bulk Power Transmission Agreements (BPTAs) signed by all the expected beneficiaries of the transmission system. Under the new proposed mechanism all the Designated ISTS Customers (DICs are default signatories to the Connection and Use of System Agreement (CUSA), which also requires these DICs to pay the point of connection charge, which covers the revenue of transmission licensees. This commercial arrangement would also facilitate financial closure of transmission investments.

   - The proposed mechanism would facilitate integration of electricity markets and enhance open access and competition by obviating the need for pancaking of transmission charges.

   - The National Electricity Policy requires the transmission charges to reflect network utilization. The Point of Connection tariffs are based on load flow analysis and capture utilization of each network element by the customers.

   - The distinction between generation and demand customers would provide siting signals to the DICs, through accurate transmission charges vis-à-vis . The current decision of generators is based on just the fuel transportation costs. With the implementation of the new transmission pricing mechanism – where transmission charges are locationally differentiated – the generators will have to take a view both on transmission costs of electricity and transportation costs of fuel.

   - The proposed framework will greatly facilitate fair and transparent competition for case-1 bids. Under the current methodology, the case-1 bid processes are severely distorted because of pancaking, and this results in pit head / hydro plants not being competitive for inter-regional bids. The impact of pancaking is further amplified in such bid processes because of application of escalation factors to transmission charges over a 25 year period. The proposed methodology will remove such difficulty.

   - The regulations facilitate solar based generation by allowing zero transmission access charge for use of ISTS and allocating no transmission loss to solar based generation. Solar power generators shall be benefited in event of use of the ISTS. Since such generation would normally be connected at 33 kV, the power generated by such generators would most likely be absorbed locally. This would cause no / minimal use of 400 kV ISTS network and might also lead to reduction of losses in the 400 kV network by obviating the need for power from distant generators. Further, this is also aligned with the objectives of the Jawaharlal Nehru National Solar Mission which is *"to establish India as a global leader in solar energy, by creating the policy conditions for its diffusion across the country as quickly as possible."*. The cost of energy from solar based generation is in the range of Rs 14-18 / kWh and application of ISTS charges and losses would further reduce the acceptability of power generated from solar sources. This regulation encourages solar based generation.

7. There are two basic variants of the PoC methodology - the Marginal Participation Method and the Average Participation Method. The proposed methodology is a hybrid of these two methodologies and incorporates the positive aspects of both the variants.

8. The regulations called the Central Electricity Regulatory Commission (Allocation of Inter State Transmission Charges and Loss) Regulations, 2010 set out the principles, operational and implementation aspects of the proposed transmission pricing methodology. The following sections describe the regulations in brief.

B. Objective and Scope of the Regulations

1. The regulations lay down the methodology for sharing of transmission charges for the use of Inter-State Transmission System (ISTS) and transmission losses in the ISTS, in accordance with the National Electricity Policy and Tariff Policy.
2. These regulations do not deal with the determination of Approved Transmission Charges (ATC) of the transmission licensees and mechanisms for computation of overall losses. Determination of ATC and methodology of computation of overall losses shall be as per the regulations of the Commission from time to time.
3. ISTS Charges and Losses shall be shared amongst the following categories of users who use the ISTS in accordance with these regulations:-

    (a) Power Station directly connected with the ISTS;

    (b) State Electricity Boards / State Transmission Utilities / Distribution licensees using ISTS; and

    (c) Any other bulk consumer directly connected with the ISTS.

C. Principles and Mechanisms for allocation of ISTS charges and losses

Principles

The core principles of the proposed methodology are as follows:

- The ISTS is a single integrated "common-use" national network for use by all DICs
- All DICs would have to pay charges (or loss compensation) depending on where they are placed in the national network. For example, for generators located close to a load centre, the charges would be relatively less, and vice-versa. Similarly, demand located near generation hubs would have relatively lesser charges or losses allocated to them.
- One national network is envisaged for the computation of charges and loss allocators once the entire national network is frequency integrated. However till the Southern Region Operates in a separate frequency regime, the computations for NEW grid and SR grid would be undertaken independently.
- The sharing of transmission charges is not related to individual transactions. Thus the transaction management (including on the trading platforms) become simpler and the merit order is maintained.

Mechanisms

1. The core methodological aspects are outlined below:

- AC Load Flow based "Point of Connection (PoC)" charging methodology.
- The PoC will be the hybrid of the Marginal Participation and the Average Participation Methods. Greater details on the methodological aspects using the above two methods is provided in Annexure-I to the regulations.
    - The Marginal Participation Method computes utilization of each transmission line because of injection / withdrawal at each generation / demand node.
        - **Role played by Average Participation Method:** The selection of slack buses would be based on the Average participation Method.

        - **Role played by Marginal Participation Method:** The injection at each bus needs to be counter-balanced by a corresponding increase in demand at certain buses – called the slack buses. Similarly, an increase in demand at a load bus needs to be counter-balanced by a corresponding increase in generation at certain buses. The Marginal Participation Method is used to compute network utilization by injection / withdrawal at each node.
    - **Justification for the use of the hybrid approach:** The method considered here is a hybrid of the marginal and the average participation method. In the Marginal Participation Method, discussed in the staff paper issued on May 15 2009, the slack buses dispersed all over the network were considered. A criticism of the approach was that it would not be prudent to assume that an increase in generation in one state (say Punjab) would impact demand in distant nodes (say Maharashtra). The hybrid approach addresses this criticism of the Marginal Participation method proposed originally. On the other hand, the Average Participation method tends to select buses which are geographically and electrically proximate. The hybrid approach uses the slack buses selected by the Average Participation Method but allocates the burden of transmission charges on various nodes using the Marginal Participation Method. This, thus, results in generators feeding "geographically and electrically proximate" demand first and then the demands which are "geographically and electrically distant". In other words, generators are primarily linked with nearby demand first and only net imports or exports are linked with external nodes. Consideration of the Marginal Participation method for determination of the burden of transmission charges helps consider the burden of transmission charges of lines which may not be in the path (incidental flows) identified by the Average Participation Method but are identified to be affected by flows along the identified path. Further, from an efficient pricing standpoint, Marginal Participation Method helps relate the nodal charges with the marginal benefits provided by each line to the node being priced.
    - Using the above mechanism, the marginal participation factors for allocation of charges and losses to each node are computed.

2. Each generator will submit the following data to the Implementing Agency (IA):
    a. MWs tied up in long term contracts for each season (the seasonal definitions are provided in the regulations) as required by the IA and the maximum injection expected to be registered in the system on account of such contracts. The transmission charges and loss allocators will be computed based on the MWs committed in long-term contracts and approved by the NLDC. These long term MWs submitted by the generators may be modified by the NLDC based on past trends, future expectations and to ensure that Kirchoffs' laws – in the process of load flow simulations to compute transmission charges and loss allocators - are satisfied.
    b. The capacity of the power plant
    c. The capability curve of the generator

3. Each demand customer will submit the following data to the IA:

    MWs withdrawal as tied up in long term contracts and the maximum demand expected to be registered in the system on account of such contracts. The transmission charges and loss allocators will be computed based on the MWs committed in long-term contracts and approved by the NLDC. These long term MWs submitted by the demand customers may be modified by the NLDC based on past trends, future expectations and to ensure that Kirchoffs' laws – in the process of load flow simulations to compute transmission charges and loss allocators - are satisfied.

4. The CTU shall supply the following information to the IA:
    a. In the first year of implementation: The network details – electrical characteristics of each line and other network elements required for the conduct of an AC Load Flow Analysis
    b. ATC attributed to each line and circuit kilometers
    c. In the subsequent years, the CTU shall submit increments to the transmission capacity and the revised line-wise ATC.

5. The IA will run the PoC methodology to allocate transmission charges and losses. This data shall be submitted for peak and other than peak conditions for January 15, March 15, May

15, August 31, and October 30, such that any of these days is not a Weekend/Public Holiday.

6. The nodal transmission charges and loss allocators will be aggregated over zones determined based on the electrical and geographic proximity of the nodes, such that the difference between nodal charges of nodes being combined into a zone are within a logical range. While multiple generation zones shall be considered in a state, for each state there shall be a single demand zone. This is essentially because, the interface of the CTU network with the State is usually at either 400 kV or 220 kV nodes which are generally owned by the state transmission utilities. The transmission bills by the CTU are generally raised on the STU or the SEBs where state utilities have not been unbundled. While the nodal charges for access by demand customers will be made available to the State Utilties, the manner of application within the state would be left to the state utilities. This may change when the states implement a 'Point of Connection' based transmission pricing mechanism.

7. The Commission intends a gradual transition to the new transmission pricing mechanism to reduce the impact on various states because of the adoption of the new transmission pricing mechanism. Therefore, in the initial period the 50% of the total ATC of the ISTS will be recovered from the new point of connection based transmission pricing mechanism and the balance 50% will be recovered from by applying the postage stamp (uniform pricing) mechanism. The Commission recognizes the need to introduce 'efficient' signals through PoC based transmission tariffs and shall reduce the percentage of ATC to be recovered from the postage stamp mechanism over time. For implementation, in the first two years, the Commission will apply transmission charges and losses based on a combination of PoC methodology and a Postage Stamp (i.e., one single charge / loss percentage for all DICs) methodology in a ratio of 50:50. The Commission may consider increasing the locational signal by reducing the proportion of the postage stamp component over time.

8. No differentiation in rates is proposed between the long term, medium term and short term users of the transmission system. However these would be accorded decreasing order of priority in event of system constraints.

D. Accounting of Charges

1. The RPCs shall maintain accounts of the ISTS charges to be collected from each DIC of the ISTS based on information provided by the CTU. The bills would be raised based on the final accounts certified by the RPCs.

2. The proposed arrangements will ensure full recovery of the charges of the transmission licensees and losses incident. Provisions have been made to ensure that there is no over-recovery (or under-recovery), and any such over-recovery (or under-recovery) will be adjusted in the following period.

3. The DICs would be responsible for paying for the higher of the requisitioned or actual generation / demand. In event of the actual generation / demand exceeding the requisitioned generation / demand (which is the sum of the long term and short term generation / demand approved by the RLDC) in more than 5% of the hours in a month, penal charges would apply.

4. For long term customers availing supplies from Inter-State Generating Stations, the charges and losses payable by such generators for such long term supply shall be billed directly to the respective long term customer based on their share of capacity in such generating stations.

5. In the case of transactions through the power exchange, the demand DIC shall be pay the zonal PoC charges applicable to the zone where such demand customer is physically located and the generator DIC will pay the transmission charges as per the PoC transmission charge applicable to the zone where such a generator is located.

6. In the case of transactions through the power exchange, the schedule of the demand customer shall be reduced by the percentage loss attributed to the zone where such demand customer is physically located and the scheduled generation of the generator will be increased by the percentage loss attributed to the zone where such a generator is located.

E. Billing and Collection

1. The CTU shall be responsible for raising the transmission bills for the entire ISTS irrespective of ownership, collection and disbursement of transmission charges to all other transmission licensees, whose assets have been used for the purpose of inter-State transmission of power. For such services the CTU shall be entitled to levy and recover a charge from DICs as approved by the Commission.
2. The billing for ISTS charges for all constituents shall be on the basis of Rs./MW/hour, and shall be raised by the CTU on a monthly basis.
3. Billing shall be done on the basis of:-

   (a) The metering data at the ISTS transfer point; and

   (b) The energy accounts approved by the RPCs.

4. Each DIC shall ensure that the charges payable by them are fully paid within the time-frame specified in the CUSA or the amended BPTAs. Each player connected with the ISTS shall provide payment security as determined through detailed procedures developed by the Implementing Agency. The level of such payment security shall be related to the Approved Demand or Approved Injection.
5. Commercial Mechanism: Connection and Use of System Agreement (CUSA)

   The constituents and service providers on the ISTS would be required to enter into new transmission services agreement or modify the existing BPTAs to incorporate the new tariff and related conditions. Such agreement shall govern the provision of transmission services and charging for the same shall be called the transmission Connection and Use of Service Agreement (CUSA) and shall, inter-alia, provide for:-

   (a) Detailed commercial and administrative provisions relating to allocation of ISTS charges and losses based on principles derived from these regulations;

   (b) Provisions on metering, accounting, billing and recovery of charges for the ISTS from the constituents;

   (c) Procedures for declaration and approval of contracted capacity at each node or an aggregation of nodes in the ISTS for each DIC;

   (d) Detailed procedures and provisions for connection by the DICs at the inter-connection points, including the processes for requisitioning new inter-connection capacity on the ISTS;

   (e) Procedures and provisions for treatment of over or under injections by the DICs;

   (f) Procedures and provisions for treatment of the delay in injection / withdrawal by DICs;

   (g) Treatment of the delay in commissioning of transmission lines;

   (h) Payment security mechanisms;

   (i) Default and its consequences;

   (j) Dispute resolution mechanisms;

   (k) Term of the agreement and the termination provisions;

   (l) Force Majeure Conditions; and

   (m) Any other matter that is relevant for the proposed transmission charge and loss allocation mechanism.

The detailed procedure for CUSA will be developed by the CTU and presented for approval by the Commission within 45 days of the notification of these regulations.

F. Information Provision in Implementation Process

1. The IA will host full information on the charges at the nodal and zonal levels for perusal of the DICs. The underlying load flow data would also be made available.
2. During the initial implementation process the Commission proposes hold workshops to further the understanding of these regulations and the proposed mechanism amongst various stakeholders.
3. The implementation process will also include training and capacity building of the associated staff of the CERC, NLDC, RLDCs, CTU, RPCs, and the State Transmission Utilities. The Commission also proposes to make the software used for the allocation of transmission charges and losses based on POC available to Implementing Agency in the interest of transparency and acceptability.
4. These future activities, along with the expected time period of their completion are provided in the table below from the date of notification of the final regulations.

Activity	**Description**	**Process Owner**	**Period**
1	Notification of regulations	CERC	Day 0
2	Formulation and notification of detailed processes	IA	Month 1 - 2
3	Formulation of CUSA and BPTA amendment	CTU	Month 1-2
4	For remaining part of FY - Network identification, Forecasting of Approved Injection and Approved Demand, ATC determination, Load Flow computations, MP method application	IA	Month 2-3
5	Parallel operations of existing and proposed system	IA	Month 4 and 5
6	Capacity Building	CERC, IA	Month 2-5
7	Commencement of transmission pricing and loss allocation under new methodology	IA	End of Month 5

G. Computation of Nodal / Zonal Charges and losses for 2008-09 Network

Following the public hearing, transmission charges / losses were computed using the hybrid methodology for the 2008-09 network. The process followed is outlined below:

1. "Typical" generator-wise Generation and state-wise demand data for summer, winter, and Monsoon seasons and for peak and other than peak conditions was considered for analysis. The above data, along with the network data was provided by NLDC.
2. The network was truncated at 400 kV level, with the help of SP&PA division of the Central Electricity Authority for the network data provided by NLDC.
3. The computations have been performed by considering the NEW grid and the SR separately.
4. The methodologies used for the determination of transmission charges and loss allocators are explained in the annexure to the regulations.
5. The nodes were combined into zones following the methodology outlined in the regulations and the annexure.
6. The zonal and nodal results are provided in enclosure to this explanatory memorandum.