FORMULATING PRICING METHODOLOGY FOR INTER-STATE TRANSMISSION IN INDIA

ATTACHMENT-I TO THE CENTRAL ELECTRICITY REGULATORY COMMISSION (SHARING OF TRANSMISSION CHARGES AND LOSSES) REGULATIONS, 2010

CENTRAL ELECTRICITY REGULATORY COMMISSION

February 09, 2010

TABLE OF CONTENTS

I PHILOSOPHY OF POINT OF CONNECTION BASED TRANSMISSION PRICING MECHANISM AND SELECTION OF THE HYBRID METHOD

Efficient pricing of a commodity or service needs to reflect the marginal cost of utilization of the underlying resources that are used in the provision of that commodity or service. The 'operational' term here is **'utilization'**. The pricing mechanism must therefore be able to capture the **utilization**, and **assign cost to the resources being utilized**.

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. 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.

1.1.1. MARGINAL PARTICIPATION METHOD

Any usage based methodology tries to identify how much of the 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 methodanalyzes how the flows in the grid are modified when minor changes are introduced in the production or consumption of agent *i*. For each of the considered scenarios (for each season) the procedure can be considered as follows:

a. Marginal Participation sensitivities A_{ij} are obtained that represent how the flow in line *j* changes when the injection in bus *i* is increased by 1 MW.

b. Total participations for each agent are calculated as a product of its net injection by its marginal participation. If net injection is considered positive for generators and negative for demands, the total participation of any agent *i* in line *j* is $A_{ij}(generation_i - demand_i)$.

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

1.1.2. AVERAGE PARTICIPATION METHOD

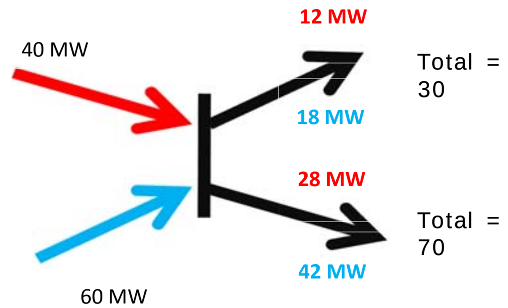
The method of average participation works as follows:

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.3 below.

Fig. 3: 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.

1.1.3. Reasons for adoption of the Hybrid Method

The Marginal Participation method (with slight modifications to the above generic frameowork) has been implemented in various countries including United Kingdom, Norway (for transmission losses), Brazil, Columbia etc. There is however little international experience in the use of the Average Participation Method. Further in the Indian context the Hybrid Method – where the slack buses are selected by using the Average Participation Method and the burden of transmission charges or losses on each node is computed using the Marginal Participation Method was found appropriate because:

- The nodal transmission access charges in the AP method have a higher variance. A compared to the range of transmission access charges in the Hybrid method (Rs 2.98 – 17.75 lakh / MW), the range in the AP method (Rs. 2.79 – 53.61 lakh / MW) is much higher.

- Further, since Hybrid method takes into account all the incidental flows – which is the reality of interconnected transmission networks – the Hybrid Method captures network utilization much better than the AP method, which simply traces the path of power from the origin to the sink(s) or vice-versa. Because of the ability of the Hybrid method to consider incidental flows, the method captures network 'utilization' better than AP method – which is one of the objectives of the NEP.

- The criticism of the MP method that the results are dependent on the choice of the slack bus is obviated because of the revised method of selection of slack buses which is based on the AP method.

II PRICING MECHANISM UNDER SELECTED FRAMEWORK

As discussed in the previous sections, based on the review of the international experience, the literature and the Indian system, the Hybrid method – a hybrid of the Marginal and Average Participation Methods has been found to be most appropriate. The details of the hybrid method are discussed in sections below.

1.1. DATA ACQUISITION: INPUTS TO THE MODEL

The transmission pricing model requires a set of inputs representative of peak and other than peak conditions in each of the three seasons – winter, summer and monsoon on the transmission system:

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes and their electrical characteristics required for load flow analysis, the associated lengths of these transmission lines and its capacity, Approved Transmission Charges (ATC) of each line
- Identification of a reference node (s)

1.1.1. NODAL GENERATION / DEMAND INFORMATION

a) Data Required for Annual process of determination of PoC transmission charges

The Designated ISTS Customers (DICs) will provide forecast injection / withdrawal information (MW and MVAr (or an assumption about the power factor to be used)) at all the nodes in the Network. “Typical” injection / withdrawal data for peak and other than peak periods for the peak and other than peak periods as defined in these regulations shall be provided to the Implementing Agency by the DICs for the following blocks of months:

- April to June
- July to September
- October to November
- December to February and
- March

The data provided by the DICs shall be approved by the STUs, validated by the NLDC for transmission constraints and shall be transmitted to the Implementing Agency for the process of annual determination of PoC based transmission charges. The ‘typical’ dates for which the forecasts will be required by the “Implementing Agency” shall be notified by it.

Nodal generation information will be based on the historical generation levels obtained from the NLDC/RLDCs/SLDCs by each generator under specific peak and other than peak conditions identified a-priori by the NLDC. This information will be updated based on information provided by the NLDC/generators/SLDCs regarding forecasts;

Nodal demand data will be based on historical demand of each beneficiary utilities (SEBs/distribution licensees) for all the months during specific peak and other than peak conditions identified by the NLDC. Forecast demand for each month as approved by the distribution utility/SEB and as approved by the SLDC will be used in the determination of the transmission use of the system charges and loss allocations

1.1.2. NETWORK DATA

NLDC shall supply the Network Data for the existing network, in the format desired by the implementing agency. The network data of the proposed network shall be supplied by the CTU. The requirement below has been given in the PTI format. The data shall inter-alia include:

a) Bus Data

I - Bus number

1 - Load bus

2 - Generator or plant bus

3 - Swing bus

4 - Islolated bus

GL - Shunt conductance, MW at 1.0 per unit voltage

BL - Shunt susceptance, MVAR at 1.0 per unit voltage. (- = reactor)

IA - Area number

VM - Voltage magnitude, per unit

VA - Voltage angle, degrees

BASKV - Base voltage, KV

ZONE - Zone

b) Generator data

I - Bus number

ID - Machine identifier

PG - MW output

QG - MVAR output

QT - Max MVAR

QB - Min MVAR

VS - Voltage setpoint

IREG - Remote controlled bus index (must be type 1), zero to control own voltage, and must be zero for gen at swing bus

MBASE - Total MVA base of this machine (or machines)

ZR, ZX - Machine impedance, pu on MBASE

RT, XT - Step up transformer impedance, p.u. on MBASE

GTAP - Step up transformer off nominal turns ratio

STAT - Machine status, 1 in service, 0 out of service

RMPCT - Percent of total VARS required to hold voltage at bus IREG to come from bus I - for remote buses controlled by several generators

PT - Max MW

PB - Min MW

c) Branch Data

I - From bus number

J - To bus number

CKT - Circuit identifier (two character)

R - Resistance, per unit

X - Reactance, per unit

B - Total line charging, per unit

RATEA - MVA rating A

RATEB, RATEC - Higher MVA ratings

RATIO - Transformer off nominal turns ratio

ANGLE - Transformer phase shift angle

GI, BI - Line shunt complex admittance for shunt at from end (I) bus, pu.

GJ, BJ - Line shunt complex admittance for shunt at to end (J) bus, pu.

ST - Initial branch status, 1 - in service, 0 - out of service

d) Transformer Adjustment Data

I - From bus number

J - To bus number

CKT - Circuit number

ICONT - Number of bus to control. If different from I or J, sign of ICONT determines control. Positive sign, close to impedance (untapped) bus of transformer. Negative sign, opposite.

RMA - Upper limit of turns ratio or phase shift

RMI - Lower limit of turns ratio or phase shift

VMA - Upper limit of controlled volts, MW or MVAR

VMI - Lower limit of controlled volts, MW or MVAR

STEP - Turns ratio step increment

TABLE - Zero, or number of a transformer impedance correction table 1-5

e) Area Interchange Data

I - Area number (1-100)

ISW - Area interchange slack bus number

PDES - Desired net interchange, MW + = out.

PTOL - Area interchange tolerance, MW

ARNAM - Area name, 8 characters, enclosed in single quotes.

f) DC Line Data

Each DC line has three consecutive records

I,MDC,RDC,SETVL,VSCHD,VCMOD,RCOMP,DELTI,METER

IPR,NBR,ALFMAX,ALFMN,RCR,XCR,EBASR,TRR,TAPR,TPMXR,TPMNR,TSTPR

IPI,NBI,GAMMX,GAMMN,RCI,XCI,EBASI,TRI,TAPI,TPMXI,TPMNI,TSTPI

I - DC Line number

MDC - Control mode 0 - blocked 1 - power 2 - current

RDC - Resistance, ohms

SETVL - Current or power demand

VSCHD - Scheduled compunded DC voltage, KV

VCMOD - Mode switch DC voltage, KV, switch to current control mode below this

RCOMP - Compounding resistance, ohms

DELTI - Current margin, per unit of desired current

METER - Metered end code, R - rectifier I - Inverter

IPR - Rectifier converter bus number

NBR - Number of birdges is series rectifier

ALFMAX - Maximum rectifier firing angle, degrees

ALFMN - Minimum rectifier firing angle, degrees

RCR - Rectifier commutating transformer resistance, per bridge, ohms

XCR - Rectifier commutating transformer reactance, per bridge, ohms

EBASR - Rectifier primary base AC volts, KV

TRR - Rectifier transformer ratio

TAPR - Rectifier tap setting

TPMXR - Maximum rectifier tap setting

TPMNR - Minimum rectifier tap setting

TSTPR - Rectifier tap step

Third record contains inverter quantities corresponding to rectifier quantities above.

g) Switch Shunt Data

I - Bus number

MODSW - Mode 0 - fixed 1 - discrete 2 - continuous

VSWHI - Desired voltage upper limit, per unit

VSWLO - Desired voltage lower limit, per unit

SWREM - Number of remote bus to control. 0 to control own bus.

VDES - Desired voltage setpoint, per unit

BINIT - Initial switched shunt admittance, MVAR at 1.0 per unit volts

N1 - Number of steps for block 1, first 0 is end of blocks

B1 - Admittance increment of block 1 in MVAR at 1.0 per unit volts.

N2, B2, etc, as N1, B1

The line-wise ATC of the entire network shall be provided by the CTU. In case a line is likely to be commissioned during a financial year, the data of the same, along with the earliest COD will be provided to the Implementing Agency by the CTU.

For the determination of the PoC based transmission charges applicable in the next financial year, all the above data shall be provided to the Implementing Agency before the end of the second week of December in each Financial year by the DICs / Transmission Licensees and other constituents as identified in the regulations.

Overall charges to be allocated among nodes shall be computed by adopting the ATC of each of the lines of the ISTS licensees, and any other line that has been designated by the respective RPCs as an ISTS line. The ATC for the lines shall be certified by the respective licensees as approved by the appropriate Commission. The ATC of the sub-stations shall be apportioned to the lines emanating from each sub-station. The ATC of the transmission assets expected to be commissioned in the Application Period would be incorporated by the Implementing Agency on the basis of provisional approvals or benchmarked capital cost and operating costs as determined using the regulations of the Commission.

1.2. COMPUTATION: TRUNCATION OF THE INDIAN GRID AT 400 KV

The determination of PoC transmission charges is required to be limited to the network owned, operated and maintained by the ISTS Licensees. "Neat" truncation of the grid at the interface of the state and the central sector boundaries is not possible because all the assets of PGCIL are not interconnected by their own assets. Preparation of a cogent network therefore requires consideration of state owned lines also.

Most of the assets of PGCIL are operated at 400 kV. For the year 2008-09, PGCIL had Rupees 221 Crores (excluding NER) to be recovered from 220 kV assets of the total ATC of Rupees 4959.43 Crores. Most of the 220 kV assets in India are owned by the state utilities. It was, therefore, deemed appropriate by the CEA that the network be truncated at 400 kV level because it would involve minimal use of the state owned lines. The voltage level for the purposes of network truncation may be revised in the subsequent years by the Implementing Agency after approval by the Commission.

The complete Network shall be truncated at 400 kV level by the Implementing Agency following the following guidelines:

1. The Implementing Agency shall run AC Load Flow on the entire Indian Grid – NEW and SR separately till these grids are synchronously integrated.

2. For each 400 kV node, the Implementing Agency shall determine the net power flowing out of each node and power flowing into each node from the power system at lower voltage levels connected to this node, to compute the net injection / withdrawal at each node from the lower voltage power system.

a. In the case of the net injection, the system below each node shall be replaced by a generator and vice-versa in the case of net withdrawal, the system below each node shall be replaced by a net demand.

3. The network thus modified will only have 400 kV assets with revised generation and load buses.

4. A truncated network for each grid condition for each season shall be obtained based on the above guidelines.

5. The Implementing Agency shall execute AC load flow on the truncated network and the truncation shall be accepted only when the (1) Slack bus generation, (2) Voltage angles at generation and demand buses match with the AC load flow on the full network.

6. The network considered for NER region will however have all the assets from 765 kV to 132 kV.

The truncated network so obtained shall be used for the implementation of the Marginal Participation methodology of transmission pricing.

1.3. IDENTIFICATION OF THE SLACK NODES: HYBRIDIZATION OF THE MARGINAL PARTICIPATION AND THE AVERAGE PARTICIPATION METHODS

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.

Thus the calculation of how much an injection (or withdrawal) at a certain bus affects the flows in the network depends on the choice of the node (s) that responds.

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 slack nodes can be considered – where the demand (generation) at all / pre-selected nodes responds pro-rata to 1 MW increment in generation (load). For the purposes of the computations in the Indian context distributed slack nodes have been considered. The selection of slack buses influences the final results prominently and therefore is a decision which must not be made arbitrarily.

The method considered here is a hybrid of the marginal and the average participation methods, and is sympathetic with the concerns of those who, in the defense of the interests of their states argue that demand in each state must first be met by the generation within the state and that the mismatches between the state generation and demand will result in export or import flows.

Truncation at the 400 kV level also allows relation of local generation and local demand and obtains a source (or a sink) for the net imports (or exports). In other words, state generators below 400 kV are primarily linked with state demand and only net imports or exports are linked with external nodes. The external slack bus (es) for each node shall be found as follows:

a. For every node in a particular scenario, Average Participation method will be applied to each generation / load located in the state under consideration. Tracing from load to generator (or from generator to load), a set of generators (or loads) (including those outside the state) and their contribution to the load (generator) is determined for each load (generator) bus.

b. Using the above choice of slack buses for each generator and load bus, marginal participation of each generator and load in each transmission line is computed.

1.4. COMPUTATION: HYBRID METHOD FOR THE DETERMINATION OF PoC TRANSMISSION CHARGES

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 Hybrid Method 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. 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. The methodology used for the selection of the distributed slack buses is explained above.

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:

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

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^{i}_{le} 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 Approved Transmission Charge of the line – computed by attributing the Approved Transmission Charge for the ISTS licensee to each line owned by it

$\frac{U_{eil}}{\sum_i U_{eil}}$ is the marginal participation factor

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.

1.5. COMPUTATION: HYBRID METHOD FOR THE SHARING OF TRANSMISSION LOSSES

1. In the application of the Marginal Participation Method for the allocation of transmission losses to various nodes in the system, the change in losses in the system (above the base case) because of a incremental injection / withdrawal at each node are computed. The change in overall system losses per unit of injection / withdrawal at each node is termed as the Marginal Loss Factor for that node. This is a numerical approximation of:

$$Marginal\ Loss\ Factor_i = \frac{\partial\ System\ Losses}{\partial\ Power\ generation/load\ at\ Node\ i} = K_i$$

2. The selection of the slack buses for absorption (supply) of the incremental injection (withdrawal) is done as per the methodology discussed above.
3. The marginal loss factors are multiplied by the generation / demand at these nodes under base case, i.e.

$$K_i \times P_i^g \quad \text{for generation nodes}$$
$$K_j \times P_j^d \quad \text{for demand nodes}$$

Where,
P_i^g is base case generation at node i
P_j^d is base case demand at node j

4. Loss Allocators for generation and demand nodes are computed by:

$$\frac{K_i \times P_i^g}{\sum_i K_i \times P_i^g + \sum_j K_j \times P_j^d} \text{ for generation node } i \text{ and}$$

$$\frac{K_j \times P_j^d}{\sum_i K_i \times P_i^g + \sum_j K_j \times P_j^d} \text{ for demand node } j$$

5. The Loss Allocators computed above are multiplied by the total system losses to allocate losses to each node in the system.

1.6. COMPUTATION: DETERMINATION OF SHARING OF ATC AND TRANSMISSION LOSSES

The simulations will be carried out by the Implementing Agency by using a software duly approved by the CERC.

The following steps shall be followed:

1. Converged AC Load Flow data for the NEW Grid and the SR grid for the truncated network shall be used directly for the implementation of the Marginal Participation method.

2. Treatment of HVDC lines: Flow on the HVDC line is regulated by power order and hence it remains constant for marginal change in load or generation. Hence, marginal participation of a HVDC line is zero. Thus, MP-method cannot directly recover cost of a HVDC line. Therefore, to evaluate utility of HVDC line for a load or a generator, the following methodology shall be applied:

   a. Step 1: Evaluate the Transmission System charges for all loads and generators corresponding to base case which has all HVDC lines in service.

   b. Step 2: Disconnect the HVDC line and again compute the new flows on the AC system. Hence, evaluate the new transmission system charges for all the loads and generators.

   c. Step 3: Compute the difference between the Nodal Charges with and without HVDC line and identify nodes which benefit from the presence of the HVDC lines.

   d. Step 4: The cost of the HVDC line is then allocated to the nodes in proportion of the benefits they derive from its presence as computed above.

In the case of SR Grid, which is not synchronously connected with the NEW grid, the 'benefits' shall be computed at nodes which were indicated to have higher transmission usage costs attributed to them 'without' the HVDC line (Talcher- Kolar).

HVDC line is modeled as a load with MW equal to P-order at the sending end and a generator with corresponding MW at the receiving end. A 'without' scenario for a HVDC line, corresponds to disconnecting the corresponding load-generation pair. Sensitivities for these fictitious loads and generators are not computed as they are not to be priced.

3. Using AC load flow, marginal participation factors shall be computed for determination of transmission system utilization due to marginal injection / withdrawal at each generator / demand node.

4. ATC for each line shall be based on the line-wise ATC provided by the POWERGRID Corporation of India Limited. Average per km ATC for each voltage level of POWERGRID lines shall be applied to the 765 kV, 400 kV, 220 kV and 132 kV lines considered in the network.

5. Hybrid Method shall be applied to system conditions as required by the Implementing Agency and approved by the CERC. Typically, these conditions will correspond with:

    - April to June
    - July to September
    - October to November
    - December to February and
    - March

    Peak and Other than peak conditions to be used for computations shall be approved by the CERC and notified by the Implementing Agency for submission of the required data.

6. Annual Average ATC of each line will then be attributed to peak and other than peak periods of each season.

7. The annual average ATC (of each period in each season) of each line is attributed to the total change in flow in each line. Therefore the ATC is allocated to each agent in proportion of the change in the flow in network branch affected by that agent.

8. Point of Connection (PoC) Transmission charges in Rs/MW/Annum and Rs/MW/hr at each node in each season will be computed.

9. Loss Allocators will also be computed along with the above simulations and as discussed above.

10. Total losses are computed, as per the present methodology, viz.,

    The total net drawal by each utility is subtracted from the sum of net injection of Inter-State Generating Stations (ISGS) and the inter-regional injections to arrive at the losses in MWh.

    All loss computations are on a weekly basis from the Special Energy Meters (SEMs) installed at all inter-utility exchange points in the region. A week for the purpose of accounting is from 0000 hours of Monday to 2400 hours of the following Sunday.

11. Using the loss allocators, the losses are allocated to each node.

1.7. CREATION OF ZONES AND DETERMINATION OF ZONAL CHARGES AND LOSSES

The proposed mechanism is based on a locational point charge (Rs/MW/month) of (Rs/MW/hr) for each grid connected entity, 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 are articulated below:

- Zones should contain relevant nodes whose 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
- Typically the zones will remain fixed in a given financial year unless significant changes in the power system during a year require re-zoning. Any such re-zoning shall however be approved by the CERC before implementation by the Implementing Agency.

1.7.1. DETERMINATION OF LOCATIONAL CHARGES IN GENERATION ZONES

The transmission access charges shall be determined for each generation zone by computing the weighted average of nodal access charges at each generation node in this zone.

In case of a generation node, where a generator is physically connected, the transmission access charges for such generators can be recovered from the demand customers who have been allocated capacity of such generators.

As discussed above, truncation of the network at 400 kV level, may in certain instances lead to net injection at nodes which may not have a generator directly connected. Transmission access charges for such generators shall be charged to the states where these nodes are located.

The weighted average transmission access charge for nodes in a zone is the zonal PoC transmission access charge for generation, e.g. in a Zone - ZZ, the following three nodes were considered in one zone: PP, AA and KK.

ZZ zone for Summer Peak Condition

	Power Scheduled (MW)	Rs –Lakh	Zonal Rs Lakh/MW
PP	24.08	163.98	
AA	107.69	825.03	
KK	160.02	1053.05	
ZZ – ZONE	291.79	2042.06	6.99

In the above table, the PoC transmission charges (in Rs Lakh / MW) to be charged to ZZ zone during the financial year are computed by dividing Rs Lakh (2042.06) by Power scheduled (291.79 MW). The per unit weighted average annual access charge is therefore, Rs. 2042.06 divided by 291.79 MW is Rs 6.99 lakh per MW.

These will be updated by the Implementing Agency based on the Network and Load in the Application Period.

1.7.2. DETERMINATION OF LOCATIONAL CHARGES IN DEMAND ZONES

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.

Transmission access charges for demand zones are computed in a manner similar to the transmission access charges for generation zones.

1.7.3. DETERMINATION OF LOSSES IN GENERATION ZONES

The loss allocators, computed at the nodal level are indicative of the percentage of losses to be allocated to each node. The total system losses, computed as per the existing methodology, will be

a. first attributed to each node by multiplying the loss allocators with the total system losses – to obtain losses in MWh attributed to each node

b. The MWh losses attributed to each node in a zone are aggregated to determine the losses attributable to each zone.

Normally the losses computed through the load flow analysis will be less than those computed through physical measurement, as per the existing methodology. Further, this also happens because the loss computations here are based on truncated network – where the losses on the 220 kV and 132 kV network are excluded. This will require scaling up of losses. The loss percentage to be applied will be based on such scaled-up losses.

1.7.4. DETERMINATION OF LOSSES IN DEMAND ZONES

The loss allocators, computed at the nodal level are indicative of the percentage of losses to be allocated to each node. The total system losses, computed as per the existing methodology, will be

a. first attributed to each node by multiplying the loss allocators with the total system losses – to obtain losses in MWh attributed to each node

b. The MWh losses attributed to each node in a zone are aggregated to determine the losses attributable to each demand zone.

Normally the losses computed through the load flow analysis will be less than those computed through physical measurement, as per the existing methodology. Further, this also happens because the loss computations here are based on truncated network – where the losses on the 220 kV and 132 kV network are excluded. This will require scaling up of losses. The loss percentage to be applied will be based on such scaled-up losses.

The above mechanism will be used to compute losses (as a percentage of energy injected / withdrawn) in each zone. In the application, for long term customers, the schedules of the demand customers will be reduced based on the percentage loss attributed to the zone where they are physically located and the percentage loss in the zone where the generation (in which the demand customer has allocated share) is located.

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.

1.8. TRANSITION MECHANISM TO THE POC BASED TRANSMISSION CHARGE AND LOSS SHARING MECHANISM

As a part of the transition to the new point of connection based transmission pricing methodology, the recovery of the ATC of the ISTS network shall be based on both the Point of Connection Method and the uniform pricing mechanism (postage stamp method) by giving appropriate weights to both. The Commission will decide the weights based on the impact of such transition on various DICs. For the first two years, the transmission charges shall be computed based on [50%] weight to the zonal charges obtained using the Point of Connection method and [50%] weight to the uniform charge allocation sharing mechanism. After a period of two years from the implementation of the proposed arrangements, the Commission shall review the weights accorded and consider increasing the locational signal by reducing the proportion of the postage stamp component.

The losses shall be attributed to the demand DICs based by reducing their requisitioned MWs. The extent of reduction shall be based on the losses attributed to each DIC based on the Point of Connection Method and the Uniform loss allocation mechanism. As in the case of transmission charges, for application to various demand DICs, the weights on the two mechanism – the Point of Connection Method and the Uniform Loss Allocation Mechanism, for determination of the losses attributable to each demand DIC shall be decided by the Commission. For the first two years, the losses attributable to each demand DIC shall be computed based on [50%] weight to the zonal losses obtained using the Point of Connection Method and [50%] weight to the uniform percentage loss allocation mechanism. After a period of two years from the implementation of the proposed arrangements, the Commission shall review the weights accorded and consider increasing the locational signal by reducing the proportion of the postage stamp component.