PROPOSED APPROACH FOR SHARING OF CHARGES FOR AND LOSSES IN INTER - STATE TRANSMISSION SYSTEM (ISTS)

1.0 INTRODUCTION

1.1 The following has been specified under Section 79 of the **Electricity Act, 2003**:

“ 79.(1) The Central Commission shall discharge the following functions, namely:-

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(d) to determine tariff for inter-State transmission of electricity;

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(4) In discharge of its functions, the Central Commission shall be guided by the National Electricity Policy, National Electricity Plan and tariff policy published under section 3. ”

1.2 The **National Electricity Policy** was issued by the Ministry of Power on 12.2.2005. The following is stipulated under section 5.3.5 of the same:

“ 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.”

1.3 Another statement, relevant to the subject, in section 5.3.4, is :

“ Non-discriminatory open access shall be provided to competing generators supplying power to licensees upon payment of transmission charges to be determined by the appropriate Commission. The appropriate Commission shall establish such transmission charges no later than June 2005. ”

1.4 The **Tariff Policy** has been issued by the Ministry of Power on 6.1.2006. Section 7 of this is devoted to Transmission. The pertinent statements in the same are :

" 7.0 TRANSMISSION

………………..The tariff policy, in so far as transmission is concerned, seeks to achieve the following objectives:

1. Ensuring optimal development of the transmission network to promote efficient utilization of generation and transmission assets in the country;
2. Attracting the required investment in transmission sector and providing adequate returns.

7.1 Transmission pricing

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(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 should be developed by CERC taking into consideration the advice of CEA. Such tariff mechanism should be implemented by 1st April, 2006.

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

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7.2 Approach to transmission loss allocation

(1) 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 CERC in this regard for inter-State transmission,

the Forum of Regulators may evolve a similar approach for intra-State transmission.

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1.5 The Commission has accordingly taken up the subject exercise, and the proposed approach, evolved in consultation with the Central Electricity Authority, is outlined below, for initiating an informed discussion. At the outset, it should be pointed out that this is a fairly complex subject, and there are no standardized solutions. Different countries have adopted or are contemplating adoption of differing approaches, each having its own implications. We would aim to adopt a pragmatic approach, which strikes a balance between dispute-free implementability and “the ultimate objective to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system” mandated under the Tariff Policy.

2.0 CRITERIA FOR TRANSMISSION TARIFF DESIGN

2.1 When formulating a transmission pricing scheme, the following objectives/aspects have to be kept in view:

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.

2.2 Since 1992, the transmission charges for the inter-State systems (except in NER) have been paid by the beneficiaries (users) on a "fixed" basis. In this scheme, the annual charges for each transmission system are determined by applying the specified norms on the capital cost. These charges, since 2003, are apportioned between the beneficiaries (the States in the concerned region) in proportion to their respective aggregated MW allocation in Central generating stations. There is a further provision to link the total payment to the transmission owner with annual availability of the transmission lines. If weighted average availability is below the specified norm, the total payment gets proportionately reduced. If it is above the norm, an incentive is paid by the beneficiaries in addition to the base annual charge. The charges for inter-regional links are shared by the beneficiaries of the two regions on 50:50 basis.

2.3 The above concept fulfils the objectives (i), (iii), (iv), (ix), (x) and (xi) listed above, and has generally been found acceptable by the concerned parties. The transmission charges paid by a beneficiary do not depend on actual power flows and distance traversed, and therefore implementation of the scheme is fairly simple and billing is dispute-free. The concept, however, does not fulfill the objectives (ii), (v) and (vi), mainly on account of not being sensitive to distance, direction and the location of load or generation. There are also instances where some beneficiaries have objected to sharing of transmission charges for the proposed additions/augmentations as per the above formula, on the ground that the new transmission elements would not benefit them in any manner.

2.4 With the new focus on commercial aspects, it is natural that the beneficiaries resist imposition of any liabilities for transmission addition/augmentation that does not benefit them directly. Particularly, as the per MW transmission costs for incremental generation are higher than those of the existing assets, pooling of the transmission charges of incremental assets is opposed by those who have lesser or no allocation from incremental generation capacities. On the other hand, operationally, in an integrated network, as the incremental transmission system gets inherently rolled into embedded network, there is equally strong reason in favour of pooling of transmission charges for the incremental transmission system with those for the existing transmission system. The entities which seek lesser or no allocation from incremental generation are generally those which have exportable surplus power. Such entities too need additional transmission capacities in the system for trading their surplus power, but may not say so. As additional transmission capacities get created out of the planned reliability margins and inherent operational margins of the incremental transmission systems, such entities, even while not having allocation from incremental generation, would derive benefit from the incremental transmission system, and should, therefore, share its transmission charges.

2.5 Further, it is necessary to adopt a scheme wherein transmission charge liability for a beneficiary drawing power from a near-by power station is much less than that associated with power drawal from a remotely located power station. In other words, the techno-economic viability of a load-centre station should duly take into account the reduced cost of associated transmission system, and this should get reflected in tariffs charged. The transmission tariff design should also take into account the shift in system development towards all-India concept with setting up of generation projects for multi-regional benefit and emergence of National grid system. These issues need to be addressed urgently, particularly for associated transmission systems planned for generating stations in the pipeline.

3.0 TWO DISTINCT ASPECTS

3.1 Transmission tariff design has two distinct aspects. One is the formulae which determine the total charges that the transmission system owner would get. The other is the formulae which determine how these total charges are to be shared by the customers/beneficiaries of the transmission system. These need to be discussed separately.

3.2 Once a transmission system has been commissioned, the only costs to be incurred by the system owner are those on account of O&M, insurance (if any)/contingencies, and investment recovery. There are no “variable” costs (which vary with power flow), and all components of annual cost (which transmission system owner needs to recover), i.e. return on equity, interest on loan, depreciation/amortization, O&M charges, taxes, insurance and interest on working capital, are “fixed”. This being so, if total transmission charges are linked to power flows on the transmission system, there could be big mismatches. In years of high power flows, the transmission owner would get high returns (without having done anything special). In years of low power flows (for no fault of his), the transmission owner would have a revenue shortfall. This would not be logical, particularly in an unbundled scenario. The rational approach would, therefore, be to adopt a scheme in which the transmission owner is paid a fixed amount every year, which covers his reasonable costs, irrespective of power flows.

3.3 The one parameter over which the transmission owner has a control, and which is indicative of his efficiency, is the sustained availability of his system. He needs to be given an incentive for minimizing the outage of transmission system elements. In other words, if the weighted average annual availability of his system is above the specified norm, he should get an incentive over the normative annual fixed cost. If the availability is below the norm, the total payment to him should be below the normative annual fixed cost. There is another way this can be looked at. The customers / beneficiaries can benefit from the transmission system only when it is in service, and therefore the total transmission charges they pay can be directly linked to (and may even be made directly proportional to) the number of hours of weighted average availability of the transmission system in a year.

3.4 As mentioned in para 2.2 above, the present tariff scheme for inter-State transmission system is already in line with the above, i.e. 3.2 and 3.3. It would also work towards the objective of "attracting the required investment in transmission sector and providing adequate returns" as stressed in the Tariff Policy, since the investor would be assured that his revenue would not come down on account of reduced power flows. Besides, there would be no perverse incentives for the transmission owner to influence or distort dispatch decisions away from true merit order. This is particularly relevant for the Central Transmission Utility which is a transmission system owner as well as the operator of the regional load dispatch centres. In view of all these factors, we propose to continue with the present philosophy, wherein total charges payable to the transmission owner are independent of power flows and are determined according to norms specified by the Commission, both for the existing inter-State system and for the future additions / augmentations.

3.5 In case a transmission system or a part thereof is built by a party selected through tariff based competitive bidding, the normative annual fixed charge would be that arrived at through the bidding process.

3.6 The second aspect, i.e. how the total charges payable to the transmission owner are to be shared by the customers / beneficiaries of the transmission system is very subjective, complex, and contentious, particularly on account of issues brought out in para 2.3, 2.4 and 2.5 above. It has been observed that these issues are delaying the finalization of transmission systems associated with some new power projects. In turn, this could delay or bottle up the power plants themselves, which would be most undesirable. The Commission would therefore like to address these issues expeditiously.

4.0 SHARING OF TRANSMISSION CHARGES FOR REGIONAL SYSTEMS BY BENEFICIARIES

4.1 The inter-State transmission system (ISTS) presently in operation is almost entirely owned by Power Grid Corporation of India Ltd (PGCIL), which has been notified by the Central Government as the Central Transmission Utility (CTU). It has been gradually built over the last 30 years, primarily as the "associated transmission system" (ATS) of the power plants set up by different Central Public Sector Undertakings (CPSUs) on regional basis. Even where some elements of the ISTS have been built under the heading of system strengthening, these are mostly the necessary supplements to the ATS, which for some reason were not taken up as a part of the original ATS.

4.2 Annual base transmission charges for the above system have been historically determined on a cost-plus basis, applying the specified norms, which were last notified by the Commission on 26.3.2004 for the period from 1.4.2004 to 31.3.2009. While the charges are determined ATS-wise, they are aggregated region-wise for billing purpose, and are shared by all beneficiaries (the parties having allocations in the Central power plants) in proportion to the respective aggregate MW allocation. In this scheme, the relative location of a beneficiary in the region, and his distance from the concerned power plants, is overlooked. As a consequence, all beneficiaries in a region pay transmission charges at the same per MW rate. Apportioning of transmission losses amongst the beneficiaries is also done on a similar basis, i.e. pro-rata to total MW allocation, irrespective of location.

4.3 While the above approach has generally been accepted and reconciled to, questions of equity have been raised by some beneficiaries in certain cases. The extracts of National Electricity Policy and Tariff Policy quoted above also require that the transmission tariff be sensitive to distance and direction. As such, it is necessary to see how these shortcomings can be overcome. However, all practical aspects must be duly considered. It is of utmost importance that we do not get into intractable complications due to a hasty action, particularly where we are contemplating major changes in a system which has been working for many years, generally satisfactorily.

4.4 Our regional grids are really a mesh, wherein power flows through multiple paths from the numerous generating stations to load centres spread all over. Power flows vary considerably over the day, and some lines even see a reversal of power flow when hydro stations come in during peak-load hours. In such a situation, very elaborate technical studies and exercises would be required if transmission charges are really to be reallocated between beneficiaries according to distance and direction, and in an equitable manner. Any short cuts or ad-hoc approaches could lead to serious disputes. The Commission would, therefore, like to proceed cautiously.

4.5 A distinction between the transmission system already in operation, and the future augmentation would be helpful in this matter. The existing system built over the last 30 years has comparatively low annual charges (due to historical cost and loan repayment), and beneficiaries have accepted sharing of these charges pro-rata to MW allocations. In view of these, the question of equity (regarding distance and direction sensitivity) has much lower significance for the existing system as compared to that for the future augmentation. On the other side, the Commission has to ensure that the transmission charges for the existing system continue to be paid by the beneficiaries in a timely and dispute-free manner. It is, therefore, proposed that the present system of sharing the transmission charges of the existing regional inter-State systems be continued, except for the following changes.

4.6 While the 400 kV lines of ISTS constitute a mesh, which provides the requisite redundancy and can be logically stated to be beneficial for all beneficiaries in a region, the step-down transformers and downstream systems (where presently included in ISTS) can be rationally identified as elements which serve only the local (one) beneficiary. It is, therefore, proposed to segregate the transmission charges for these (including proportionate charges for common facilities in substations), and make them a liability of the local beneficiary only. We propose to effect this change from 1.10.2007. The CTU (PGCI) shall have to carry out the required transmission charge segregation by 30.6.2007, and obtain the Commission's approval latest by 30.9.2007. This approach would apply to all future transmission addition/augmentation as well.

4.7 Only a general rule is stipulated in para 4.6 above. There could be exceptions. For example, one 220 kV substation, presently under ISTS, may be supplying power to two beneficiaries. In such a case, transmission charges for the 400/220 kV transformers and downstream system have to be apportioned to the two beneficiaries. In the North-Eastern Region, the entire ISTS upto 132 kV shall continue to be pooled on regional basis. In other regions, all 220 kV and 132 kV lines taking off from Central generating stations, which belong to PGCI, shall continue to be pooled on regional basis, as at present.

4.8 In most cases, the energy drawals of the beneficiaries are presently metered on the upstream (400 kV) side of the step down transformers (even where the transformers are owned by PGCI). Transmission losses in these transformers and the system down stream are thus being absorbed by the individual beneficiaries already. The present transmission loss apportioning would, therefore, be compatible with the proposal in para 4.6 and metering points would not have to be shifted.

4.9 In case the Commission comes across, during the discussions on this subject, any other clear-cut case where transmission usage is by one beneficiary but the charges are being pooled (and thereby thrust on others) in an unjustifiable manner, the Commission may consider segregation of the same in a similar manner as proposed in para 4.6.

4.10 Beneficiaries in the North-Eastern Region (NER) are still paying the transmission charges for ISTS under a different scheme, known as Uniform Common Pooled Transmission Tariff (UCPTT). It was devised many years ago, keeping in view the special circumstances then existing in NER. Under it, the beneficiaries pay charges for ISTS at a certain paise per kWh rate, and the revenue of the transmission company depends upon the energy generated at Central Stations in the region. It is time now for NER too to move to the more rational scheme of “fixed” transmission charges, as is adopted in the other four regions of the country. The Commission proposes to effect this change from 1.4.2007. Power Grid Corporation of India has already filed its tariff petition for NER for the current tariff period which should enable the Commission to notify the new transmission tariff for the existing NER system before 31.3.2007.

4.11 One simplification that the Commission would like to discuss is to freeze the sharing of transmission charges for the existing ISTS, which presently keeps varying, though marginally, from month-to-month on account of changes in allocations out of unallocated part of the Central generating capacity. It is proposed that it be frozen with effect from 1.4.2007 in proportion to the aggregated permanent MW allocation of the beneficiaries in the Central generating stations as on 1.4.2007.

5.0 SHARING OF TRANSMISSION CHARGES FOR FUTURE ADDITIONS/AUGMENTATION

5.1 India already has fairly well-developed regional grids, which by-and-large cater to the requirements of the existing generating capacity and load. When a new generating station (or extension) is planned, the required transmission system augmentation is also planned simultaneously. It can generally be said that the necessity of this transmission system augmentation (commonly referred to as the "associated transmission system" – ATS in short) has primarily arisen because of the proposed generation addition. It would, therefore, be logical to stipulate that the identified beneficiaries/customers of the new generating capacity should pay for the above i.e. the associated transmission augmentation as well.

5.2 This is in fact not a new approach: it has been followed at the inter-State level, and has generally been accepted by all concerned. However, the practice followed so far has been to pool the charges of the new transmission system with those of the previously existing regional system, and to apportion the total charges between the beneficiaries in proportion to MW allocations arrived at after pooling the new generating capacity with the previously existing capacity. This again has been satisfactory so far because all such generation has been CPSU-owned, and all States of a region have had allocations in all such stations. The position would now change, with entry of privately-owned generating stations in which only a few States or parties may have contracted shares, as also with establishment of mega generating stations having beneficiaries across the regional boundaries.

5.3 The Commission hereby proposes to stipulate that the pooling described in the previous paragraph shall not be mandatory or automatic with effect from 1.4.2007 in respect of new power plants, i.e. those plants no generating unit of which is declared under commercial operation up to 31.3.2007. The ATS of a new power plant may still be pooled with the existing regional ISTS, if all regional beneficiaries agree in writing to such pooling, and in this case transmission of power from the new power plant shall get the priority at par with that given to the existing Central generating stations, over the entire augmented system. If such pooling is not agreed to by any of the concerned parties, the new ATS shall be treated separately, in spite of the fact that the new system is to operate with the remaining system in an integrated mode. In this case, transmission charges for the associated transmission system of the new power plant shall be paid only by the identified customers of that power plant. Also, the liabilities for paying transmission charges for the remaining transmission system shall not change on account of this augmentation of generating capacity and transmission system. Transmission of power from the new power plant shall have the first priority on the new ATS, but a lower priority on the existing ISTS, in this case.

5.4 Further, in the latter case, if the associated transmission system has been constructed to also cater to any future generation addition or for system strengthening not directly attributable to the associated power plant, the transmission charge payment liability of the power plant's customers shall stand appropriately reduced. The remaining portion of the augmentation's transmission charge shall be either pooled with the previously existing regional system, or assigned for deferred recovery, depending upon the circumstances. There could be pragmatic variants as well, e.g., a hybrid approach, in special cases, to meet the ultimate objective. We do have the required framework, of coordinated planning for transmission development under the umbrella of CEA and statutory responsibilities of CTU and STUs.

5.5 The total transmission charges payable to the owner(s) of the transmission augmentation shall be determined as per prevailing norms (according to relevant CERC regulations), except for the competitively bid part, if any. How these charges have to be shared by the beneficiaries/customers is discussed later on (in para 5.7). The above approach shall also apply to the inter-regional links being built/to be built as a part of associated transmission systems. It is expected that the foregoing stipulations would assure the parties setting up or proposing to set up new power plants that their customers would not be required to pay transmission charges more than what is reasonable. While the tendency for over-building in ATS of private power projects would be discouraged, it would be possible to build extra transmission capabilities in such ATS for catering to future requirements, on justifiable considerations of ROW and overall transmission optimization, without distorting the economic viability of the new power projects.

5.6 The stipulations in para 5.3 and 5.4 above are expected to induce "optimal development of the transmission network to promote efficient utilization of generation and transmission assets in the country", are a necessary step towards sensitizing the transmission charges to distance and direction, as mandated in the Tariff Policy, and would directly address the concerns of beneficiaries enumerated in para 2.4 and 2.5.

5.7 In case the ATS of a new power plant is to be commercially pooled with the existing regional ISTS, its transmission charges would automatically get shared by the regional beneficiaries as per section 4.0. In case the new ATS is not to be so pooled, the sharing of transmission charges by the beneficiaries of the new power plant shall be decided on case-to-case basis for the present. As a general guideline, the transmission charge sharing may be in direct proportion to the plant capacity allocation in case receiving points of all beneficiaries are at comparable distances. If different beneficiaries require new lines of widely differing lengths, it may be more appropriate to adopt MW-mile concept. After gaining some experience, the Commission may stipulate more specific guidelines, in due course.

5.8 The following is stated in National Electricity Policy dated 12.2.2006 and reiterated in section 7.1(4) of the Tariff Policy dated 6.1.2006 :

"Prior agreement with the beneficiaries would not be a pre-condition for network expansion."

We presume that the intent of this provision is to enable timely and optimal augmentation of transmission system, even if some of the so-called beneficiaries have no interest in it and are objecting to it for some reason. The intent cannot be to thrust unreasonable liabilities on unwilling beneficiaries. The approach proposed in para 5.3 and 5.4 would ensure that there is no heart-burning during operationalisation of the above quoted policy provision.

5.9 Any transmission augmentation clearly identified for strengthening the regional system (distinct from ATS) shall be pooled with the existing regional system for payment of transmission charges.

6.0 SHARING OF TRANSMISSION CHARGES FOR INTER- REGIONAL LINKS

6.1 The following inter-regional links are presently in operation in India:

(i) 2 x 250 MW Vindhyachal HVDC BtB between NR and WR

(ii) 2 x 500 MW Chandrapur HVDC BtB between WR and SR

(iii) 1x500 MW Sasaram HVDC BtB between NR and ER

(iv) 2 x 500 MW Gazuwaka HVDC BtB between ER and SR

(v) 2000 MW Talcher - Kolar HVDC Bipole between ER and SR

(vi) 400 kV D/C Rourkela - Raipur line between ER and WR

(vii) 220 kV D/C Budhipadar - Korba line between ER and WR

(viii) 220 kV S/C Budhipadar - Korba line between ER and WR

(ix) 400 kV D/C New Siliguri - Bongaigaon line between ER and NER

(x) 220 kV D/C Birpara - Salakati line between ER and NER.

(xi) 400 kV D/C Muzaffarpur - Gorakhpur line between ER and NR

6.2 Except for (vii), all of these are owned and operated by the CTU, i.e. Power Grid Corporation of India/its JV. Power flow over the HVDC links, i.e. (i) to (v), can be and is controlled as per instructions of the RLDCs. On the remaining links, which are A.C., power flow depends on the relative load-generation balance in the connected regions. The Talcher - Kolar HVDC (v) is a part of the associated transmission system of 4 x 500 MW Talcher-II STPS dedicated to SR beneficiaries. As such, its transmission charges are borne entirely by the beneficiaries in SR. The 220 kV S/C Budhipadar - Korba line (viii) has had a special dispensation, for some time, but its transmission charges are now shared by ER and WR beneficiaries in 50:50 ratio. The 400 kV New Siliguri - Bongaigaon line is a segment of the original 400 kV D/C Malda - Bongaigaon line (the whole of which has been treated as an inter-regional link till date). 220 kV D/C Birpara - Salakati line has been a part of the Chukha Transmission System, and its transmission charges have been borne entirely by ER beneficiaries. The 400 kV D/C Muzaffarpur - Gorakhpur line, commissioned recently, is a part of ATS of Tala HEP, but its charges are presently shared by ER and NR beneficiaries in 50:50 ratio.

6.3 As for the other inter-regional links listed at (i), (ii), (iii), (iv) and (vi), the basic formula applied in the past has been that of the transmission charges being shared by the two regions in 50:50 ratio. The charges borne by a region are in turn shared by the regional beneficiaries in proportion to their aggregate MW allocation in the Central Stations in the region. The 220 kV D/C Budhipadar - Korba line (vii) is a State-sector line owned by Orissa and Chhattisgarh. Transmission charges for 400 kV D/C Malda - Bongaigaon line were meant to be paid by ER and NER beneficiaries in 50 : 50 ratio, but only ER is paying its part. The NER beneficiaries pay transmission charges for ISTS under a different formula (Uniform Common Pooled Transmission Tariff – UCPTT), which does not presently cover the transmission charges for 400 kV D/C Malda - Bongaigaon line.

6.4 After formalization of “open access” in 2004, a part of the charges for the above inter-regional links are being paid by the “open access” customers utilizing these links, and the liability of regional beneficiaries comes down to the extent of 87.5% of the payment by such open access customers. In case of congestion, the open access customers have to pay a charge that comes out from the process of bidding.

6.5 At the time when 50:50 concept had emerged in late Eighties, sustained and high-volume power flows on inter-regional links, as are taking place today, were not foreseen. The generation and transmission planning was still region-wise, aiming at regional self-sufficiency. Consequently, it was projected that these links would be used occasionally (PLF of 20-30%), for providing support to a region under crisis from the other region (s), on a reciprocal basis. The present situation is much different. There are significant allocations made by Ministry of Power from Central generating stations in one region (ER) for beneficiaries in other regions. Surplus power, of substantial quantum, is also being sold across regional boundaries in a scheduled manner (open access), through traders or bilaterally. Besides, energy is being exchanged between the regions as Unscheduled Interchange (UI). In view of the changed circumstances, it is necessary to have a fresh look at the 50:50 concept, link-wise.

6.6 The ER beneficiaries, notably Bihar, have been complaining for many years that the 50 : 50 formula has caused them to pay for assets which do not benefit them. They have been told in the past that the inter-regional links enable export of surplus power of ER, which reduces their liability for payments to Central generating stations in ER. This reasoning for asking ER beneficiaries to pay 50% of the inter-regional links’ transmission charge was justified prior to implementation of Availability Tariff, but is not valid any more. The matter needs a fresh look from this angle as well.

6.7 The 2000 MW Talcher - Kolar HVDC link, from its inception, was seen and planned as a part of the associated transmission system of 4 x 500 MW Talcher-II power plant located in Orissa. Since its capacity was fully allocated to beneficiaries in SR, it was logical to treat this inter-regional link differently. Accordingly, its entire transmission charge is shared by the SR beneficiaries only. Further, since all SR States have allocations in Talcher-II STPS, the transmission charges of the link have been pooled with those of the previously existing ISTS of SR, and are shared by the SR beneficiaries in proportion to their aggregate MW allocations in Central stations including Talcher-II STPS. We are not aware about any complaints in the matter, and the approach appears to be satisfactory. No change in transmission charge sharing of this link is, therefore, proposed.

6.8 The 2 x 500 MW Gazuwaka HVDC BtB is another link between ER and SR. After commissioning of Talcher-II STPS, this link provides another path for power from Talcher-II to SR beneficiaries, besides providing a path for scheduled bilateral exchanges and UI between ER and SR. The power flow direction is mostly from ER to SR, and its power level (and therefore its utilization, vis-à-vis Talcher - Kolar) is decided by SRLDC, in order to optimize the transmission losses and voltage profile in the SR. As such, it can be said that the SR is the beneficiary of this link, and should pay its transmission charge in full.

6.9 The 1 x 500 MW Sasaram HVDC BtB link between ER and NR has been used till recently to its full capability for transmitting surplus power of ER and NER to the power-deficit NR. It has been very clearly benefiting only the NR, and this status continues even after commissioning of 400 kV D/C Muzaffarpur –

Gorakhpur line. Its full transmission charges should, therefore, be paid by NR beneficiaries.

6.10 The 2 x 250 MW Vindhyachal HVDC BtB link between NR and WR has a varying power flow, both from NR to WR and from WR to NR, depending on relative load-generation balance on the two sides. Both the regions can reasonably be construed as its beneficiaries, and the present 50:50 sharing of transmission charges by NR and WR may continue. The same is also the case with 2 x 500 MW Chandrapur HVDC BtB between WR and SR.

6.11 The 400 kV D/C Rourkela - Raipur line, the 220 kV D/C Budhipadar - Korba line (State-owned) and the 220 kV S/C Budhipadar - Korba line link ER and WR, and provide the path for surplus power of ER and NER to flow to WR beneficiaries. The power flow would never reverse, except for a short time in case of a major contingency. One can, therefore, say that they primarily benefit WR, and their transmission charges should be paid fully by the WR beneficiaries. The State-owned line listed above operates in parallel with the other lines belonging to the CTU, serves the same purpose, and therefore its total charges should also be borne and shared by all WR beneficiaries.

6.12 The 400 kV D/C Malda - Bongaigaon line, though conceived as a part of the associated transmission system of NEEPCO's Kathalguri CCPP in Assam, has subsequently been treated as an inter-regional link between ER and NER. It has been recently looped-in-looped-out at Purnea and New Siliguri in ER. Lines under construction from Tala HEP in Bhutan and Teesta-5 (in which NER beneficiaries have no share) would also connect up at New Siliguri. With these changes, it would be logical to treat only the 400 kV D/C New Siliguri - Bongaigaon line as the inter-regional link. Further, during the hearing of Petition No.59/2005 at Kolkata on 20.1.2006, data on power flow pattern from April 2004 to December 2005 was presented by ERLDC as per which power flows in both directions on this link. While NER is generally the power exporter, it had a net energy import during January and December 2005. During the lean (non-monsoon) months, power flows from NER to ER during evening hours and from ER to NER during the remaining hours, generally. The above 400 kV D/C link, by strongly synchronizing the NER system with the much larger ER-WR system, provides the requisite grid stability and security to NER. It can, therefore, be said that although power flow is mostly from NER to ER, the link (400 kV D/C New Siliguri - Bongaigaon) provides enough benefits to NER to justify transmission charge sharing on 50:50 basis between ER and NER, presently. (As and when new power projects get commissioned in NER with allocation for beneficiaries elsewhere, the above sharing formula would have to be changed.) The 400/220 kV sub-stations at New Siliguri and Bongaigaon shall, however, be treated as parts of the ER and NER systems respectively.

6.13 The 220 kV D/C Birpara - Salakati line constitutes another link between ER and NER, and could be given the same treatment as 400 kV D/C New Siliguri - Bongaigaon line. However, it has a historical background which needs being taken into account. It was built as a part of the ATS of Chukha HEP in Bhutan, power from which is allocated only to the ER beneficiaries. It also provides the direct path, at least notionally, for flow of power from Kurichhu HEP in Bhutan (again allocated only to ER beneficiaries) to ER. Though it supplements the 400 kV D/C New Siliguri - Bongaigaon line in secure synchronization of NER with ER-WR system, the 400 kV D/C line is otherwise sufficient for this purpose. Considering all these aspects, we propose to continue with the existing status of the 220 kV D/C Birpara - Salakati line and 220/132 kV Salakati sub-station, i.e. retain them as parts of ATS of Chukha HEP, the charges for which are payable by ER beneficiaries only.

6.14 The 400 kV D/C Muzaffarpur - Gorakhpur line has been constructed as a part of ATS of Tala HEP for supplying power to NR States. Its transmission charges should therefore be borne by NR beneficiaries only.

6.15 To recapitulate the above, the transmission charges for existing inter-regional links should be shared in the following manner in the coming years :

(i) 2 x 250 MW Vindhyachal HVDC BtB :
by NR and WR in 50:50 ratio

(ii) 2 x 500 MW Chandrapur HVDC BtB, including 400 kV D/C Chandrapur - Ramagundam line: by WR and SR in 50:50 ratio.

(iii) 1 x 500 MW Sasaram HVDC BtB, including 400 kV D/C Sasaram - Allahabad line: by NR

(iv) 2 x 500 MW Gazuwaka HVDC BtB, including 400 kV D/C Jeypore – Gazuwaka line: by SR

(v) 2000 MW Talcher – Kolar HVDC: by SR

(vi) 400 kV D/C Rourkela - Raipur line: by WR

(vii) 220 kV D/C Budhipadar - Korba line: by WR

(viii) 220 kV S/C Budhipadar - Korba line: by WR

(ix) 400 kV D/C New Siliguri - Bongaigaon line:
by ER and NER in 50:50 ratio, for the present.

(x) 220 kV D/C Birpara - Salakati line: by ER

(xi) 400 kV D/C Muzaffarpur - Gorakhpur line: by NR

6.16 The above is proposed to be implemented with effect from 1.4.2007. The transmission charges for each of these links are already specified separately, except for (ix). PGCI should quickly separate it out from 400 kV D/C Malda - Bongaigaon, and have it approved by CERC.

6.17 Extensive transmission systems running from NER / ER to the other regions are under development / construction for carrying power from large thermal and hydro-electric projects (e.g. Subansiri, Barh, Kahalgaon-II) to their beneficiaries in NR and WR. Synchronisation of SR with the rest of the country is also contemplated in the coming years. These would have a considerable impact on the entire transmission system of the country, and may call for a review of the approach presently proposed. The Central Electricity Authority (CEA) has very recently suggested identification of certain transmission elements (all inter-regional links including Talcher - Kolar HVDC, all 765 kV network, 50% of 400 kV system in ER and NER, and 15% of the 400 kV system in the other regions) as national transmission assets, transmission charges for which may be shared on a national basis, with appropriate distance and directional sensitivity. This would be a major change from the existing mechanism, requiring discussions and detailed technical exercise. We propose that these be undertaken in 2008-09, with the goal of introduction of the proposed scheme, on 1.4.2009, the date when the new tariff period would start. The CEA proposal is however enclosed as Annexure-1 for advance information.

7.0 "OPEN ACCESS" ON THE INTER - STATE TRANSMISSION SYSTEM

7.1 The ISTS in operation as on date has mostly and primarily been developed for transmission of power from Central generating stations to the beneficiaries having defined allocations in the generating capacity of these stations. It is for this reason that transmission of power from these stations has the first priority in usage of the existing ISTS, and would always be the last to be curtailed in case of a transmission constraint. The present scheme of sharing of transmission charges is also founded on, and is in tune with the above two factors.

7.2 "Open access" on the ISTS basically means utilization of the surplus transmission capacity by parties to transmit power other than the Central generation allocations. The following statements in section 9(2) of the Electricity Act, 2003 is very relevant:

" Provided that such open access shall be subject to availability of adequate transmission facility and such availability of transmission facility shall be determined by the Central Transmission Utility or the State Transmission Utility, as the case may be. ”

7.3 A transmission line, transformer or a transmission system as a whole would normally have a surplus capacity on account of (i) load variation over a day, (ii) standard equipment sizing in large steps, (iii) parallel or contra-flows, (iv) outage of generating units, (v) planned redundancy in transmission, (vi) provision of extra capacity for future generation/load growth, etc. The surplus capacity would keep changing due to its very origin, and may significantly come down (or even go negative) in case of outage of parallel elements. As a consequence, power flows on ISTS under “open access” would always have an element of uncertainty; their curtailment may be ordered whenever a transmission constraint develops (and their curtailment would relieve the situation). It is for this reason that the Commission, in its regulations has specified a much reduced transmission charge (only 25%) for the open access customers, out of which one-fourth is to be retained by the transmission system owner as extra income, and three-fourth is to go toward reduction of total transmission charges payable by the long-term customers of the ISTS, i.e. the beneficiaries of Central generation.

7.4 In the light of the experience of the past two years, the Commission proposes to simplify the procedure for availing “open access” on ISTS in near future. One of the contemplated measures is elimination of transmission charge for short-term open access, but with application of incremental losses, as explained later on.

7.5 With the increased demand for inter-regional power flows and consequent congestion on some of the inter-regional links, it has become necessary to allocate the capacities of these links between different beneficiaries. In its orders/regulations on “open access”, the Commission has laid down certain procedures under which RLDCs are required to allocate the link capacities, in case of a congestion, through a process of bidding. We aim to simplify this procedure. Besides, the present bidding process overlooks the fact that regional beneficiaries have been paying for many years the full transmission charges in certain ratios, irrespective of link utilization in the past, and therefore have a lien on proportionate link capacities. We propose to set this right.

7.6 It is, therefore, proposed that with effect from 1.7.2007, the capacities of inter-regional links shall stand allocated (in percentages) to the beneficiaries of the importing region, in proportion to their respective shares of the link's transmission charge. They shall be free to schedule imports up to their allocation in the link's capacity available for scheduled transfer, without any additional payment for link usage. They shall also be free to let another party utilize a part of their allocation on their own terms, with prior written advice to the concerned RLDC.

7.7 Any schedulable inter-regional link capacity not utilized by the concerned beneficiaries shall be available to others for short-term open access, purely on as-and-when-available, first-come-first-served basis, without payment of any charges for link usage. The clear underlying principle is that payment of transmission charges is directly related to long-term lien over the concerned transmission asset, and vice-versa.

8.0 APPORTIONING OF TRANSMISSION LOSSES

8.1 Transmission losses are a phenomenon of physics, and are unavoidable. Over a given transmission system, they keep varying over time, depending on power flows, voltage profile, reactive flows, etc. The transmission system owner has no control over these, and hence on losses, except that outage of a transmission element increases the power flow on parallel paths, which increases the total losses. In our scheme, the total transmission charge payment to the transmission owner is already linked to availability of transmission elements, which should induce him to minimize the outages. Nothing further need be done to induce reduction of losses as far as he is concerned.

8.2 The beneficiaries / users of the transmission system can contribute to reduction of transmission losses by reducing drawal of reactive power, thereby reducing reactive flows and improving the voltage profile. This too is induced in our scheme through charges for reactive energy exchange, specified in the Indian Electricity Grid Code (IEGC). However, as far as power flows are concerned, the objective is not to reduce the transmission losses but to achieve overall optimization, i.e. economy dispatch. For example, meeting the consumer demand during off-peak hours by drawing power from distant pit-head stations (which means a lower energy cost, but higher transmission losses) would be more cost effective than drawing power from a local generating station (with a higher energy cost), provided the energy cost differential is higher than the cost of transmission loss difference.

8.3 In our overall scheme, the scheduling and dispatch of generation has been decentralized and delegated to SLDCs. Overall optimization then requires that the States get the correct economic signals. They already see the variable cost of Central generating stations through energy charge rate in ABT. They also need to see the correct transmission loss associated with transmission of power from Central stations. However, as of now, the States see only the average transmission loss for the whole regional ISTS, and not the transmission loss caused by their own drawal of power from Central stations. Due to this, the variable cost of a Central pit-head station as seen by a State at its door-step is same irrespective of the location of the State. It should not be so. The variable cost at its door-step as actually seen should be lower for the State in which the pit-head plant is located, than for a distant State.

8.4 In other words, we need to move ahead from the present practice of apportioning the regional ISTS transmission losses to all beneficiaries in proportion to their scheduled drawal, irrespective of their relative location and distance from the Central generating stations. The tariff Policy also stipulates loss allocation "on the basis of average losses arrived at appropriately considering the distance and directional sensitivity". The Commission too has contemplated such a move in its tariff notification dated 26.3.2004, under section 27(vii) and 45(viii):

" For calculation of net drawal schedules of beneficiaries, the transmission losses shall be apportioned (in proportion) to their drawal schedules for the time being.

Provided that a refinement may be specified by the Commission in future depending on the preparedness of the respective Regional Load Despatch Centre. "

8.5 Implementation of loss allocation with distance and directional sensitivity, and in an equitable manner, requires considerable technical work, including extensive load flow studies, power tracing, etc. We would urge the RLDCs to initiate these at an early date, aiming to implement it in their respective regions by 1.10.2007. The scheme should be simple and practicable, not necessarily aiming to be very precise.

8.6 In the first instance, distance-based and direction sensitive loss allocation shall be done for different scenarios (low-hydro, high-hydro, etc.) for supply of Central generation allocations to the beneficiaries. (In due course, this would include supplies from new power plants under long-term contracts to parties who pay the transmission charge for ATS of those plants.) The results obtained shall be applied in the daily scheduling process, net drawal schedule of a beneficiary on its periphery being its aggregate ex-power plant schedule minus apportioned transmission loss. Thereafter, each open access transaction shall be superimposed on the base load flows, one-by-one, incremental losses shall be worked out, and charged to the respective transaction. This would ensure that open access transactions do not adversely affect any third party.

8.7 During the hearing of Petition No.59/2005 at Kolkata on 20.1.2006, it was complained by the ER beneficiaries that power flow from NER and SR to NR and WR through the ER system was increasing the transmission losses in the ISTS of ER. While NR and WR benefited in terms of increased power supply for their customers, and utilities in NER and SR earned profits through this inter-regional sale of power, the ER beneficiaries had to bear the impact of increased transmission losses in their system. This inequity would be addressed once the approach given in para 8.6 is applied, at least as far as scheduled sale is concerned.

9.0 TREATMENT FOR UNSCHEDULED INTERCHANGE (UI)

9.1 In the discussion so far, there is a basic premise that the existing regional ISTS has been built over the years primarily for transmitting Central generation to the beneficiaries. It is for this reason that its transmission charges are to be paid by the identified beneficiaries of the concerned generating stations, and in proportion to their aggregated MW allocations. It also follows that the allocated power flows have the first priority in this system's usage, and the transmission losses are booked to the beneficiaries account in proportionate manner.

9.2 However, actual power flows over various parts and elements of the ISTS vary from time to time, and differ from those which would result from flow of allocated power only. The deviations are on account of many factors: variations in beneficiaries' drawal due to consumer demand variation, supplementary supplies that the beneficiaries contract for (under "open access"), inadvertent/deliberate deviations from schedules, etc. The issue here is as to what should be the mechanism for charging the concerned parties for such use of transmission system and for additional transmission losses that they cause.

9.3 As far as the ISTS owner is concerned, he does not have to be paid anything extra for such power flows: in our scheme of "fixed" transmission charges, he is already being reimbursed for all his costs by the regional beneficiaries on a regular basis. There is neither any extra effort that the ISTS owner has to put in, nor any extra costs that he has to incur, on account of such flows. The question then only is that of equity: what should be the charges for such usage of transmission system vis-à-vis its usage for drawing their Central allocations by the identified long-term beneficiaries? As mentioned earlier, the latter has the first priority, and the identified beneficiaries absorb only proportionate losses, whereas "open access" transactions have a lower priority (meaning that they may have to be curtailed if a transmission constraint arises), and are to be charged for incremental transmission losses (which are roughly twice of the proportionate losses in percentage terms). The two being on very different footings, no great inequity would arise if it is stipulated that no transmission charges are to be levied for short-term usage of as-and-when-available surplus capacity of ISTS under "open access".

9.4 There is one more argument in favour of not levying any transmission charge for "open access" transaction. Some of these may involve transmission of power in a direction opposite to that of normal power flow. They would thus reduce line loadings and transmission losses, and strictly speaking, they should have a negative transmission charge and also get a credit for transmission loss reduction. We can, however, keep things simple by stipulating no transmission charge levy - positive or negative, and no credit if incremental transmission loss is negative.

9.5 Yet another argument for zero transmission charge for “open access” is that of parity with unscheduled interchanges (UI). The latter too constitute sale-purchase of power, at a floating price and without any prior commitment or schedule. Due to perpetual variability, it is impractical to apply transmission charges to UI, which means that this mode of sale-purchase is free of transmission charge. Scheduled sale-purchase of power (under open access) should not be disadvantageous compared to this, which means that it should also be free of transmission charge levy.

9.6 Let us now examine the above parity aspect in respect of transmission loss treatment. We have already decided, as explained in para 8.6, to charge “open access” transactions for incremental losses. However, the UI transactions as of now are free of any impact of transmission loss change caused by them. This is not fair to “open access”. Taking a specific case to illustrate the point, let us assume that a utility in Maharashtra purchases 50 MW of power from a utility in Chattisgarh under “open access”. Load flow studies may show that the resulting power flow increase in WR grid increases the ISTS loss by 2 MW. Accordingly, in its daily scheduling, WRLDC would decrease the net drawal schedule of Chattisgarh by 50 MW and increase the net drawal schedule of Maharashtra by 48 MW, while the latter would pay to Chattisgarh for 50 MW at the agreed rate. In comparison to this, if the same power exchange takes place as UI, Chattisgarh shall get paid for 50 MW at the UI rate, Maharashtra would pay for only 48 MW at the UI rate, and the 2 MW of incremental loss would get pooled for sharing by all WR beneficiaries.

9.7 To remove the above anomaly, it is necessary to introduce a differential of 4% in the UI rates applicable for Chattisgarh and Maharashtra. If the UI rate for Chattisgarh at a particular time is 300 paise/kWh, it should be 312.5 paise/kWh for Maharashtra. UI payment by Maharashtra would then fully cover the UI payment to be made to Chattisgarh. Such a move would also be in the true spirit of bringing a distance and direction sensitivity. Further, an under-drawal by Maharashtra would get it payment at this higher UI rate, which is justified because of consequent system loss reduction. An over-drawal by Chattisgarh similarly reduces the transmission loss, and justifies application of the lower UI rate.

9.8 The Commission proposes to introduce a system of differential UI rates on the lines described above, with effect from 1.10.2007, along with loss allocation as per para 8.5. RLDCs may initiate the necessary technical studies accordingly. Further, a special problem of ER has been noted in para 8.7. Power is flowing from NER to NR and WR via ER, without being scheduled, i.e. as UI. The resulting increase in transmission losses in the ER grid are going to the account of ER beneficiaries, which is not at all fair. The required equity can be brought in by introducing appropriate differentials between the UI rates of different regions; UI rate in NER may be slightly lower than in ER (say around 98%), and UI rate in NR and WR may be slightly higher, say around 103% of the UI rate in ER, at any particular frequency.

9.9 As per CERC regulation dated 30.01.2004, as amended on 21.02.2005, the "short-term open access" customers are required to pay transmission charges (for use of system) and operating charges (to compensate the concerned RLDC/SLDC for the extra effort), and bear energy losses on average basis. For reasons explained in the above discussion, we propose to stop payment of short term open access transmission charges from 1.7.2007. The concept of incremental transmission losses shall, however, be introduced from 1.10.2007.

9.10 Some may say that our proposal not to levy any transmission charges for short-term "open access" is not in line with section 5.3.4 of the National Electricity Policy quoted in para 1.3 of this paper. Our response would be that contracted supplies from generators to licensees shall all be covered by long-term arrangements: PPAs and transmission service agreements between the concerned parties. The present impediments have been adequately addressed in section 5.0 of this discussion paper, and the proposed approach would enable non-discriminatory access to transmission, through advance agreement on payment of appropriate transmission charges.

9.11 The use of transmission system would fall in two broad categories. One would be through a long-term lien over the system, with payment of transmission charges and benefits of proportionate transmission loss and first priority. The other would be through use of as-and-when available spare capacity, free of charge but bearing incremental losses, and low priority.

10.0 TRANSMISSION LINES OWNED BY STATES AND OTHERS

10.1 Many States have their own 400 kV and 220 kV lines which supplement / complement the PGCI-owned ISTS. Satisfactory performance of such State-owned lines too is very important for the secure operation of the regional grids. However, as of now, many of the States are not monitoring and stressing on the availability of their own lines. We would, therefore, urge all SERCs to urgently introduce mechanisms in their respective States for encouraging improvement in the availability of such lines. Similar measures are also required for BBMB and DVC, keeping in view that, unlike PGCI, they have no commercial incentives for availability improvement presently.

10.2 Many State-owned lines are supplementing or can supplement the ISTS for enhanced inter-regional transfer of power. Commercial mechanisms need be developed to encourage their being made available by the respective owners to the RLDCs for enhancing inter-regional power transfer either in radial mode or in synchronous mode, as appropriate in each case.

11.0 OTHER APPROACHES APPLIED IN TRANSMISSION PRICING

11.1 As mentioned earlier, transmission pricing is a very complex subject, particularly in case of a large inter-connection. On one hand, power / energy coming from different generating stations get mingled in the transmission system, and it is not easy to trace, even notionally, the route taken by the MWs scheduled from a generating station to a particular beneficiary. On the other hand, the power flows over most of the lines are continuously changing. Various approaches have been talked about and tried out in different countries for recovery of transmission cost from the users/beneficiaries. We have proposed a hybrid and incremental approach which we feel is pragmatic and suitable for our conditions, and generally meets our stated objectives.

11.2 However, for the sake of completeness of the discussion on the subject, other approaches adopted elsewhere should also be mentioned. The simplest possible scheme would comprise of a flat per kWh transmission charge, on all-India basis or on region-wide basis. This is commonly referred to as "postage stamp" scheme, and is inherently insensitive to distance and direction. While it meets objectives (x) and (xi) listed in para 2.1, it miserably fails in respect of all other objectives. "Zonal postage stamp" scheme would be a marked improvement, and if judiciously formulated, can meet objectives (ii) and (vi) in addition to (x) and (xi). "MW hour-Mile" scheme would be a further improvement, but it too would be counter-productive as far as objectives (iv) and (ix) are concerned. As a general rule, any scheme in which payment of transmission charges is linked to energy would fail on (iv) and (ix), and therefore must be avoided as far as possible.

11.3 "MW-Mile" scheme would take care of objectives (iv) and (ix), provided the "MW" used in the formula is the allocation in generating station capacity and not the actual MW drawal. The first objective can also be met by suitably resetting the per MW per km rate periodically, which in turn would satisfy objective (v). However, judicious determination of the per MW-km rate and application of the scheme in a large interconnection are not easy, and we must move with all due caution.

11.4 Further, “MW-Mile” too is insensitive to direction. It is also felt that “MW-Mile” should be applied as a concept (with flexibility to moderate/deviate in appropriate circumstances), rather than as a rigid formula. For example, charges for substation and transformers can not be covered by MW-Mile formula. These are best covered through “connection” charge, which in fact has been proposed in para 4.6, though not by that name. UK and Norway use what is sometimes called “Point Tariff”, by applying a zone-wise or location-specific rate which discourages generation addition in north and load growth in south, to suit their respective geographic disposition of load and generation. In this scheme, there is no pairing of generation and load for levying transmission charges within a country, since there is nothing corresponding to our ATS. Designing a “Point Tariff” for India would not be easy. Yet another scheme is “zone-to-zone” matrix proposed by CEA, in which generation and load are paired.

11.5 It is a practice in some countries to levy a per MWh transmission charge to supplement the per MW or MW-Mile charge. The former is used by the transmission owner to buy power/energy for making up the transmission losses. In our scheme of things, the transmission losses are adjusted in scheduling itself, and transmission owner does not have any liability on their account. Consequently, the per MWh component is also not necessary.

11.6 On the whole, it appears that MW-Mile, Point Tariff and zone-to-zone are three distinct concepts which could be evaluated for application in the long-term, such as when discussing sharing of charges for national transmission assets in 2008-09 contemplated in para 6.17.

12.0 CONCLUDING REMARKS

12.1 In section 7.2(1) of the Tariff Policy, it is mentioned that based on the methodology laid down by CERC regarding transmission loss allocation, the

Forum of Regulators may evolve a similar approach for intra-State transmission. We have to point out here that we have looked at only the inter-State transmission system in the above discussion. The criteria applied for ISTS may not always be applicable / appropriate for the intra-State transmission, which may require an independent exercise.

12.2 To summarise the above discussion, it is proposed to:

(i) segregate step down transformers and downstream system, and charge only the local beneficiary for them w.e.f. 1.10.2007. (para 4.6).

(ii) terminate UCPTT in NER and introduce the concept of 'fixed' transmission charges from 1.4.2007 (para 4.10).

(iii) stop automatic pooling of new ATS with existing ISTS with effect from 1.4.2007 (para 5.3).

(iv) rationalize transmission charge sharing of inter-regional links, w.e.f. 1.4.2007 (para 6.15).

(v) introduce capacity allocation to beneficiaries for inter-regional links, w.e.f. 1.7.2007 (para 7.6).

(vi) implement distance and direction sensitive loss allocation for supplies from Central generating stations on proportional basis, w.e.f. 1.10.2007 (para 8.5).

(vii) introduce differentials in UI rates of different regions, and for beneficiaries in each region, to compensate for transmission losses, w.e.f. 1.10. 2007 (para 9.8).

(viii) simplify "open access" procedures and withdraw transmission charges for "short-term open access" w.e.f. 1.7.2007, and apply incremental losses w.e.f. 1.10.2007 (para 9.9).

(ix) undertake further rationalization in 2008-09 to cater to long-term transmission development (para 6.17).

12.3 The underlying theme in the approach outlined above has been to move from the past philosophy of pooling all costs and transmission losses, and charging all beneficiaries on a uniform averaged basis, to charging the beneficiaries according to what they individually cost, depending on their respective distance from the source of power supply. We have also endeavoured to move in pragmatic steps, which can be implemented in a dispute-free manner without a risk of disrupting the existing system. It may also be recalled that a structured study on “Bulk Power and Transmission Tariffs and Transmission Regulations” was carried out by M/s ECC of USA in 1993-94, and its recommendations were accepted by the Govt. of India as a covenant of World Bank and ADB loans to PGCI. The foregoing proposal is generally in line with those recommendations as well.

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