पावर ग्रिड कारपोरेशन ऑफ इंडिया लिमिटेड
(भारत सरकार का उद्यम)
POWER GRID CORPORATION OF INDIA LIMITED
(A Government of India Enterprise)
पावरग्रिड
केन्द्रीय कार्यालय : "सौदामिनी" प्लॉट सं. 2, सैक्टर-29, गुड़गाँव-122 001, हरियाणा
फोन : 2571700 - 719 फैक्स : 2571760, 2571761 तार 'नेटग्रिड'
Corporate office : "Saudamini" Plot No. 2, Sector-29, Gurgaon-122 001 Haryana
Tel. : 2571700 - 719, Fax : 2571760, 2571761 Gram : 'NATGRID'

संदर्भ संख्या /Ref. Number **: CSO/CERC/**

Dated: 19th March, 2010

To,

Secretary,
Central Electricity Regulatory Commission,
3rd and 4th Floor, Chandralok Building,
36, Janpath
New Delhi- 110 001

Sub: Draft Regulations on Sharing of Transmission Charges and Losses

Ref.: 1. No.L-1/16/2010/CERC Public Notice - Dated: 9th February, 2010
2. No. L-1/16/2010/CERC – Public Notice - Dated the, 8th March, 2010

Sir,

Views /Suggestions on the CERC Draft Regulation on "Sharing of Transmission Charges and Losses" on behalf of NLDC/ RLDCs are enclosed herewith.

Thanking you,

Yours faithfully,

वी.वी. शर्मा
19/3/10

(V. V. Sharma)
General Manager (System Operation)

Enclosure: As above

Comments on the 'Draft Regulation on Sharing of Inter State Transmission Charges and Losses' issued by CERC vide public notice dated 9th February 2010

Background

The comments on the 'Draft Regulation on Sharing of Inter State Transmission Charges and Losses' issued by CERC vide public notice dated 9th February 2010, are being submitted on behalf of the five Regional Load Despatch Centres (RLDCs), National Load Despatch Centre (NLDC) and Corporate System Operation (SO) department of POWERGRID.

Views/Suggestions on the CERC "Approach Paper on Formulating Transmission Pricing Methodology for inter-State Transmission", issued on 15th May 2009 were submitted to Hon'ble Commission on 28th July 2009 *(copy enclosed).* The views/suggestions being submitted now may be seen in conjunction with our earlier submission.

The comments are segregated in two parts. Part-1 pertains to the Draft Regulation and Explanatory Memorandum while Part-2 pertains to the Attachment-1 and the Nodal-Zonal results enclosed with the Draft Regulation.

The comments are focused on the implementation aspects only.

Part-1: Comments of RLDCs/NLDC/SO on Draft Regulation and Explanatory Memorandum

1. The Draft Regulation along with the Explanatory Memorandum with associated attachments provides a road-map to implementing para 5.3.4 and 5.3.5 of the National Electricity Policy and para 7 of the Tariff Policy. The Honourable Commission has designated National Load Despatch Centre (NLDC) as the Implementing Agency for the first two years. **NLDC/RLDCs look forward to the Honourable Commission's guidance and support in discharging this ambitious target**.

2. The regulation would give a huge boost to the highly specialized faculty of power system simulation studies in the country. The regulations would also facilitate sharing of power system network data among different transmission utilities and also be instrumental in setting up a common reference database file for any discussion based on offline simulation. Subsequent to the notification of these

regulations power system modelling and simulation results would have a direct and substantial commercial implication for the DICs. The regulations would also give further push for deployment of better mechanisms for forecasting demand/injection as well as for archival and retrieval of historical data at SLDCs/RLDCs/NLDC/generating stations. **These developments would definitely help System Operation and are therefore welcomed by the NLDC/RLDCs/SO.**

3. Chapter 2 states the objective and scope of the draft regulations. We recognize the intricacies involved in developing and implementing a scientific, fair and transparent transmission pricing mechanism. We appreciate the herculean efforts and tireless initiatives taken up by the Hon'ble Commission particularly in the last five years for translating the policy directives in National Electricity Policy and the Tariff Policy of the Government of India into a comprehensive draft regulation in Feb 2010.

   Presently in case of short term (collective) transactions, a uniform adhoc zonal/nodal transmission charges in terms of Rs./MWh are applied while the transmission losses are paid in kind by both generators and demands depending upon the region where they are located. Considering the complexities involved in migration from the existing uniform transmission pricing mechanism to the nodal transmission pricing mechanism, **it is proposed that to start with, the proposed mechanism for sharing of transmission charges and loss allocation may be applied to only one segment of the market i.e.; Short Term Open Access market. Application of this in short-term market will ensure that the existing mechanism does not get disturbed as we already have point of connection method for collective transaction through Power Exchange. Based on the experience gathered during a reasonable period the methodology may be applied to long-term and medium term transactions as well.**

4. As per Chapter 6 Regulation 15 (2), the Implementing Agency has been entrusted with the responsibility for smooth transition to the new mechanism, for dissemination of information and for capacity building among DICs and the ISTS licensees. A stringent timeframe of five months has been suggested for implementation of the new methodology. As per Chapter 6, regulation 15 (1) and Explanatory Memorandum para F, the IA has to formulate five procedures and get them approved within 2 months of the notification of the final regulation. We appreciate CERC's thrust on accelerated migration to the new methodology and as designated Implementing Agency for the first two years, NLDC would put in its best efforts to facilitate fast implementation of the new methodology. However the involvement of NLDC in working out transmission charges based on existing uniform pricing methodology as well as in the formulation of the new methodology

has been very limited. **Considering the stakes involved and the complexity of the whole exercise, it is suggested that adequate time may be given to the Implementing Agency to comprehend the proposed methodology, build a team of people, draft the procedures, set up the necessary infrastructure (for information exchange with the DICs, data processing, carrying out studies, generating nodal and zonal charges), streamline internal processes and carry out confidence building trial exercises.**

5. The proposed methodology for sharing of inter-State Transmission charges and losses would involve carrying out studies with the help of complex algorithms and working out the Nodal/Zonal charges. Capacity building in such a highly specialized area is extremely crucial and would be a pre-requisite. However it may kindly be appreciated that capacity building in this highly specialized area would take much longer time than normally expected for other routine activities within the utilities. The Explanatory Memorandum indicates a time line for capacity building of the associated staff of the CERC and IA in the month 2-5. **The allowed time in the draft regulations would be highly inadequate, as the involved persons would have to comprehend the new philosophy in the right perspective, understand and learn the power system simulation, appreciate the data set needed for the process, understand each step of the process, intermediate results at the end of each step and the final output which would be converted to meaningful results. Such capacity building need to be done quickly at NLDC, RLDCs, RPCs, CTU etc., and it needs to be replicated amongst the State utilities so that they are able to absorb the new philosophy. In view of the above it is proposed to revise and reorient the implementation process. It is proposed that capacity building can start from April'10 and target date for implementation of new methodology can be decided later on say 01.04.2011.**

Alternatively the Regulation itself could give adequate time for capacity building (through workshops, interaction, mock trials etc.) and validation of network data and software before actual implementation and in order to address the teething troubles, the Regulations could have a provision for 'Removal of difficulties' to facilitate appropriate amendments to the regulations.

6. Honourable Commission had given an order dated 28th March 2008 in petition no. 85/2007 (suo-motu) on the issue of 'Proposed Approach for Sharing of Charges for and Losses in Inter-State Transmission system.' Through the order CERC had directed that the new ICTs at 400/220 kV and below voltage level would continue to be shared by only the state drawing power from them and not pooled with other Inter State Transmission System (ISTS) assets while the 765/400 kV ICTs would be part of the pooled ISTS assets. As per Chapter 4, Regulation 7 (f) of the present regulation the Annual Transmission Charges of the substation is to be apportioned to the lines emanating from each substation. In this regard, the methodology for sharing the substation cost between 765 kV and 400 kV lines might be indicated separately by the Commission so that the ATC per ckt. km can be worked out for each voltage level. Likewise the other issues that need to be clearly stated in the regulations are as under:

a. The concept of Associated Transmission System (ATS) would cease to exist as all ISTS assets would be pooled
b. The present concept of sharing of the cost of inter-regional links would no longer exist for the NEW grid as the hybrid method would be applied for the entire NEW grid. For Southern Grid however, the existing philosophy that Gazuwaka HVDC back to back and Talcher-Kolar HVDC bipole would be shared by SR only would continue while Bhadrawati HVDC would be shared by SR and WR in the ratio of 50:50.
c. A clear verdict is required in respect of the inter-state and inter-regional lines owned by the states and whether these would ultimately be regulated by the Central Commission both in terms of operational norms as well as the tariff.
d. As per the Indian Electricity Grid Code (IEGC), the transmission system of Bhakra Beas Management Board (BBMB) shall form part of the ISTS. The operational and commercial norms should also come in the jurisdiction of the CERC considering that the BBMB system is well meshed with the ISTS.

7. **The following suggestions with regards to Chapter 1, regulations 2 (1) may be considered**
   a. Definition 2 (1) (b): The definition of Application Period may be modified by adding including the words “peak and off-peak conditions” in the end.
   b. Definition 2(1) (c) & 2 (1) (e): As per the common understanding the demand of a control area includes generation from own resources plus drawal from the ISTS on account of approved long-term/medium term/Short-term schedules plus any unscheduled interchanges. **Therefore to avoid ambiguity, the term ‘Approved demand’ may be renamed as ‘Approved withdrawal’ and Approved Short term Demand may be renamed as ‘Approved Short- term Withdrawal’.** The term may be suitably changed in other places in the regulation particularly in chapter 4, regulation 8 (5), 8 (6) and 8 (11).

      Further the DICs may withdraw/ inject reactive power from ISTS. These MVAr flow in the system has a significant impact on the losses. The MVAr withdrawal/injection needs to be modelled during formulation of base case. Hence DICs may be asked to declare the maximum and minimum MVAr withdrawal also. **The definition of approved withdrawal may be amended as**

"Approved Withdrawal means the simultaneous maximum withdrawal in MW and MVAr approved by NLDC for all Designated ISTS Customers in a control area put together aggregated from all nodes of ISTS for each representative block of months, peak and off-peak scenarios at the interface point with ISTS."

"Approved short term Withdrawal means additional withdrawal approved by RLDC over and above approved withdrawal for all Designated ISTS Customers in a control area put together aggregated from all nodes of ISTS for each representative block of months, peak and off-peak scenarios at the interface point with the ISTS."

c. **Definition 2 (1) (d)**: The definition of Approved injection may be modified as "Approved Injection means the maximum injection approved by NLDC for the designated ISTS customer for each representative block of months, peak and off-peak scenarios at the ex-bus of the generator."
d. **Definition 2 (1) (f)**: The definition of Approved Short term injection may be modified as "Approved Short Term Injection means the additional injection approved by RLDC over and above the Approved Injection for the Designated ISTS customer for each representative block of months, peak and off-peak scenarios at the ex-bus of the generator."
e. **Definition 2 (1) (g):** Approved transmission charge (ATC) may be renamed as Yearly transmission charge to avoid ambiguity with the term available transfer capability, which is now more popularly used to indicate the margin available in any transmission corridor.
f. **Definition 2 (1) (k):** Definition of Power System should be as per the Act and it accordingly it would be preferable to delete the definition of Entire power System to avoid contradiction.
g. **Definition 2 (1) (p):** Uniform charge has been defined as the charge determined by dividing ATC of the ISTS licensee by the sum of MWs injected and withdrawn from the grid. This definition is in variance with the existing methodology of sharing of transmission charges based on weighted average of long-term allocations. Logically Uniform National Postage stamp charge should not be linked to actual generation or withdrawal. Therefore it is suggested that the definition of Uniform charge may be modified.
h. **Definition 2 (1) (q):** In the definition of Uniform Loss it is mentioned that uniform loss allocation mechanism is applied to all the demand customers. For the sake of clarity, "uniform allocation mechanism", and "demand customers" may also be defined in the definitions.

i. The term “Approved Loss” appears in Section 5(1). Same may be defined in regulation 2.
j. Inter State Transmission System (ISTS) is loosely understood by many to be the network owned and operated by the CTU. However the definition would need to cover all the transmission licensees including STUs who own and operate the Inter State Transmission System (ISTS). **Therefore it is suggested that ISTS may be defined clearly in this regulation. Likewise the intra-State Transmission System may also be defined.**

8. Chapter 2, regulation 4, specifies the categories of DICs who would share the ISTS charges and losses. It is submitted that few generators owned and operated by the States may be connected directly to ISTS. In such cases the injection by such generators would be available in the truncated network and accordingly ATC and loss shall be allocated for such injection. It may be clarified if as per para 4 (a) these power stations are to declared as DICs and separate CUSA for such DICs is to be signed (presently no such agreement available)?

9. As per Chapter 4, regulation 7 (1) (b) & (c) the base case for various identified scenarios would be formulated based on historical data and forecasts. **This implies that the RLDCs/NLDC would also have to gear up for carrying out forecast based on historical data which was hitherto the responsibility of SLDCs as per the Indian Electricity Grid Code**. Further, the Central Electricity Authority also comes out with the report on Electric Power Survey. This would create a scenario where the Implementing Agency would have several sets of figures for the forecasted load/generation and the IA would have to carry out adjustments for achieving convergence. **The IA is expected to adopt standard and transparent mechanism for such adjustments**. **Such standard mechanisms would have to be developed through a consultative process to avoid disputes and delays**.

10. As per Chapter 4 regulation 8 (3), the demand or injection indicated by the DIC shall be validated and approved by the NLDC for transmission constraints and other network security constraints. This information would be made available to the Implementing Agency on or before the end of the second week of December in each financial year for declaration. It is understood that the IA would have to publish the nodal/zonal charges and losses for 20 different scenarios (peak/off peak for five seasons) pertaining to the next financial year within the next three months. This implies that the NLDC would have to assess the transfer capability of the network for a year in advance. Presently NLDC is assessing transfer capability for approving Short Term Open Access transactions three months in advance and CTU is assessing transfer capability for approving Medium Term Open Access transactions for a year in advance and more. Further once the DICs are informed about the approved demand/injection a year in advance they may expect a right of corridor for short term open access up to the Approved short term demand/injection figures. In case of grant of STOA to a lesser extent, such action from RLDCs may attract disputes from them w.r.t. the sharing of transmission charges. **Therefore the provisions in regulation for sharing of inter-State Transmission Charges and losses with respect to the responsibility for declaration of transfer capability and for approval of demand/injection would have to be dovetailed with the existing regulations for congestion management and regulations for Open Access (Long-term, Medium term and Short-term)**. **Suitable provisions for congestion management in long-term and medium term time horizon may also have to be included in appropriate regulations.**

11. The Explanatory memorandum para C.2a and para C.3 states that the DICs have to submit the maximum injection/withdrawal as registered in the system on account of long-term contracts. This implies that the charges would be worked out based on the approved injection/withdrawal on account of long-term contracts. However as per chapter 4, regulation 8 (5), 8 (6) and 8 (11), approved short term withdrawal/injection have to be included while determining the transmission charges and while comparing the metered withdrawal/injection for any month. This aspect may be clarified. It is suggested that only long-term and medium term contracts may be considered. This would avoid the complexities associated with the dynamically varying medium-term/short-term contracts. The medium-term/short term withdrawal may vary block-wise based on the availability of corridor (congestion). They may also vary significantly from one season to other and from year to year depending upon the extraneous factors (such as socio-political factors, weather pattern, availability of own generation, conditions in electricity market etc.). Further, as per the Open Access regulations, the short term open access in inter-State transmission is to be allowed by utilization of design margins or margins created due to operational conditions. Inclusion of short-term withdrawal in the transmission charges would imply that long-term signals generated with the help of nodal/zonal charges would get distorted due to short-term contracts. Clarification would also be needed whether aggregation is to be done for all the blocks (peak and off-peak) separately for calculation of charges to be shared.

12. As per Chapter 4, regulation 9 (1), there shall be no differentiation in rates between the long term, medium term and short term DICs of the transmission system. As per Chapter 5, regulation 11 (2), the billing for ISTS changes for all constituents shall be on the basis of Rs./MW/hour. However the transmission charges applicable for Short Term Open Access customers as per the CERC regulations for Open Access in inter-State Transmission 2009 are in Rs. per MWh. The change from the earlier charges in Rs./MW/day to the present charges in Rs./MWh was done after

experiencing practical difficulties during implementation. **It is therefore suggested that transmission charges applicable for short term withdrawal may be notified in Rs./MWh.**

13. In chapter 3, regulation 6 (3)(b), it is proposed that any under recovery or over recovery during a month shall be recovered in subsequent 6 billing months on a rolling basis. **The word "recovered" may be replaced by the word "adjusted". It is suggested that since the computations are done one year in advance, such under recovery or over recovery can be either scaled up or scaled down at the time of computations itself in pro-rata manner before the billing activities start. The methodology for doing so has been elaborated as note-1 under Table 7 in the 'Approach Paper on formulating pricing methodology for inter-state transmission', May 2009.**

14. As per chapter 3, regulation 7 (1) (L), the losses shall be attributed to the demand DICs by reducing their requisitioned MWs. 50 % weightage is to be given to losses arrived from PoC method and Uniform loss allocation mechanism. As per chapter 4, regulation 8 (10), in case of transactions through PX, the scheduled generation of the generator will be increased by the percentage loss attributed to the zone where such a generator is located. Similarly the schedule of the demand customer shall be reduced by the percentage loss attributed to the zone where such demand customer is physically located. **The treatment in case of Short term schedules may be specified. Further the percentage losses have been arrived at through marginal participation which if applied in generation / withdrawal scheduling, is likely to lead to large residuals as well as subsequent complication of matching payables/receivables**.

15. Based on the provision under chapter 4, regulation 7 (1) (a) to (e) it is understood that the base case formulation has to be done by simulating the entire power system of the country. Thereafter the network shall be truncated suitably to certain voltage levels. **The voltage level up to which the transmission system is to be modelled may be specified (say up to 220 kV/132 kV level). Since the establishment of a representative case with truncated network is itself very subjective and challenging. Suitable guidelines for the same may have to be specified to avoid subjectivity and disputes. The need for truncation of the network may also be suitably elaborated in the explanatory memorandum.** Other suggestions with regards to the network modelling are as under:
    a. The modelling of ISGS embedded in the intra-State Transmission System may be specified.
    b. It may be clarified whether network truncation is to be done based on certain equivalencing method.

c. The approach to be adopted for matching the voltage and angles at generation and demand buses in the truncated case AC load flow with the voltage and angles at generation and demand buses in the full network AC load flow may be suitably elaborated.

d. There could be certain States that could be net injectors of power (say Himachal Pradesh during peak hydro). The treatment of such nodes during "zoning" may be specified in the Regulation. Alternatively the methodology used during the exercise for formulating pricing methodology for ISTS may be elaborated.

e. The Regulation may also specify the treatment to be given to the following assets:

    (i) 400 kV transmission system owned by State- Is it correct to infer from Section 7 (1) (f) and (g) that such elements are to be considered for cost sharing only for lines designated by respective RPCs as an ISTS line.

    (ii) 220 kV ISTS network: It is clear from the Regulation that the 220 kV ISTS network constructed as part of system strengthening scheme would not be considered in the truncated model. How would the transmission charges sharing be worked out for those assets?

    (iii) 220 kV state owned lines not forming part of CTU network but used for evacuating ISGS generation: Is it correct to infer that the transmission charges for such assets would be shared on the basis of long-term allocations?

f. While truncating, virtual generators / loads are being used based on injection / drawals. In case of injection or drawal at a node is for more than one DIC, the sharing methodology needs to be transparent

16. Chapter 4, regulation 7 (1) (n) states that the Implementing Agency may aggregate the charges and losses for geographically and electrically contiguous nodes on the ISTS to create zones. The criteria of geographical and electrical contiguity/proximity may be sometimes difficult to satisfy and sometimes it may lead to overlapping of control areas of the Regional entities or fragmentation of control areas. In case of fragmentation additional metering would be required. The issue has been explained to certain extent in the explanatory memorandum under para C.6 but it may be re-emphasized in the regulation itself.

17. In chapter 4, regulation 7 (o) & (p) the relaxation given to the solar based generation would further the cause of renewable energy in the country and is therefore welcome. **However the apportionment of those charges among other DICs may be specified. Similar detailing may also required for loss allocation.**

It may be clarified if the methodology suggested in chapter 4, regulation 8 (8) for long term customers availing supplies from inter-state generating stations is to be used for the solar generation.

18. Chapter 3, regulation 7 (5) (b) stipulates period of applicability of loss levels as 12 months (may be seasonally differentiated). **Moving from existing weekly to Annual loss is likely to create large difference between scheduled and actual loss**.

19. In chapter 4, regulation 7 (1) (f), the proportion in which the Annual Transmission Charges of the substation is to be apportioned to lines emanating from each substation may be clearly specified (Voltage level, ckt kilometres, twin/triple/quad conductor, effect of FSC & TCSC). The methodology used during the exercise for formulating pricing methodology for ISTS may be elaborated.

20. In chapter 4, regulation 8 (5), it is stated that the transmission charges shall be determined by multiplying the PoC charges in Rs./MW/hr with the (approved injection/demand + approved short term injection/demand) and the number of hours in the month. However in chapter 5, regulation 10 (3), it is stated that the billing shall be done on the basis of the metering data at the ISTS transfer points and the energy accounts approved by the RPCs. The above aspects may be suitably clarified. Further in case the computation is to be done on the basis of actual injection or withdrawal data from Special Energy Meters (SEM) then in all references in the Regulation the term "metering data based on SEM" may be preferably used. The term may also be defined in the definitions under regulation 2.

21. Chapter 4, regulation 8 (8) mentions that for long term customers availing supplies from inter-State generating stations, the charges and losses payable by generators for such long term supply shall be billed directly to the respective long term customers based on their share of capacity in such generating station. It is to be noted that in Indian Power Market, losses is paid in kind.

22. Transmission charges on account of long term transactions and transactions through PX have been provided under chapter 4, regulation 8(8) and 8(9) of the draft regulation. The treatment for Medium Term Open Access / Short-Term Open Access (Bilateral) can be implied indirectly from regulation 9 (1) however for the sake of clarity in the charges may also be specified explicitly. Further the methodology for arriving at the wheeling charges for intervening State Transmission System may be specified. Regulation 8(9) is also in contravention to Section 8(6),

as transactions on PX are already included in short term injections/ withdrawals as brought out in Section 8(6), This matter needs to be clarified.

23. As per chapter 7, regulation 16 (4), the DICs connected to ISTS have to submit the MW injection/drawal at various nodes during peak and off-peak period of the predefined dates (Jan-15, Mar-15, May-15, Aug-15, Oct-30). As understood from chapter 4, regulation 8 (6), this data is to be compared with the approved demand/injection by NLDC for the corresponding period. **In order to have comparison of like quantities, it is suggested that the approved withdrawal (injection) in MW may be compared with the maximum of the average MW withdrawal (injection) from (into) the ISTS as recorded by Special Energy Meter during the corresponding period. This would also remove the bias arising in the drawal/injection pattern on pre-determined dates. The timeline for data submission by DICs and transmission licensees to the Implementing Agency may have to be dovetailed with Section 5.7.4(d) of IEGC that states that the outage plan of generating units/ lines is to be finalised by 31st January of every year. It is also suggested that regulation 16 (2) in chapter 7 may be modified as – "On or before the end of the second week of December in each Financial Year, each DIC shall supply the Implementing Agency with anticipated maximum withdrawal/injection from the inter-State Transmission System during the application period of the following financial year as specified in the regulation."** Further in chapter 4, regulation 8 (3) the minimum notice period for revision in approved Demand/Injection may be specified to provide sufficient time to the Implementing Agency for carrying out studies if required.

24. Chapter 8, regulation 18 (4) of the draft Regulations state that 'the software for the implementation of transmission tariffs will be audited by the Commission before it is commissioned, and thereafter before any changes are made to the software or implementation methodology.' Apart from the power flow software commonly available with all utilities, the following additional software might have been used by the Commission's consultants in arriving at the draft regulations and the explanatory memorandum.

    i. Software to truncate the network below 400 kV and tuning it in line with section 1.2 of the Attachment-I to the draft Regulations.

    ii. Power tracing software to apply Average Participation Method to determine the slack buses to be used for each injection or demand node as per section 1.3 of Attachment-I.

    iii. Software to determine the marginal participation factor and marginal loss factor for each node as per section 1.4 and 1.5 of the Attachment-I.

iv. Software to determine the sharing of ATC and transmission losses in line with section 1.6 of Attachment-I.

v. Software to create zones and determination of zonal charges and losses in line with section 1.7 of Attachment-I.

vi. Software to collate the results of all the above which would be done for ten different scenarios (5 seasons, peak and off-peak conditions).

In the Explanatory Memorandum to the draft Regulations, Section F3 states that 'the Commission also proposes to make the software used for the allocation of transmission charges and losses based on POC available to Implementing Agency in the interest of transparency and acceptability.'

As the entire transmission charges sharing and loss apportionment is sought to be aligned with the National Electricity Policy on the basis of the studies done by the consultant, the Commission may audit the software before handing over the same to NLDC.

25. It is understood that the control area and boundary metering related issues would be taken care in the Indian Electricity Grid Code. However with respect to sharing of transmission charges the following may be clarified

   a. Few entities may be connected with both ISTS and the State transmission system. The regulations may specify the methodology for treatment of such entities.

   b. There could be some users of ISTS embedded in the State transmission system such as Feroz Gandhi Unchahar Thermal Power Plant, Narora Atomic Power Plant, Anta Gas Power Station, UT Goa, UT Daman & Diu UT Dadra & Nagar Haveli etc. The regulations may specify the methodology for treatment of such entities.

   c. Further, Changing of Scheduling jurisdiction should not result in change in payment of transmission charges and loss allocation.

Part 2: Comments of RLDCs/NLDC/SO on Attachment-I and the Nodal-Zonal results enclosed with the draft regulations on sharing of inter-State Transmission Charges and losses

26. In the CERC "Approach Paper Formulating Pricing Methodology for Inter-State Transmission in India" published on 15th May 2009, DC load flow was used in marginal participation method whereas the draft regulation talks about AC load flow. This may be elaborated.
27. The methodology for slack bus determination (as mentioned in para 1.1.3) through the Average Participation Method may be elaborated. The slack buses used for arriving zonal generation/demand access charges may also be specified.
28. The line wise Annual Transmission Charges for ISTS elements used for computation may be specified in the Attachment for better appreciation of the results.
29. Para 1.2.2a states that during network truncation the system below each node shall be replaced by a generator/load in case of net injection/withdrawal. This may be elaborated further.
30. Para 1.2.5 suggests that the truncation is to be accepted only when the slack bus generation and the voltage angles at generation/demand buses match with the AC load flow on the full network. The various alternatives for handling deviations may be elaborated. During truncation the State owned generators switched at 400 kV (Suratgarh, Anpara, Obra etc.) have been included while the ISGS switched at 220 kV (say Unchahar, Anta, RAPS, NAPS etc.) have been ignored. Would this not distort the results? Few of the above ISGS buses could have been candidates for slack bus.
31. Para 1.7.3 and 1.7.4 state that the losses computed through the load flow analysis would have to be scaled up to match them with those computed through physical measurement. The need for matching of actual losses with those arrived at from load flow solution may be elaborated. Would it be possible to compute the loss allocators without having to scaling of the transmission loss?
32. Results for 2008-09: discrepancies / inconsistencies /issues
    a. Number of nodes considered for nodal charges and number of nodes considered for nodal losses are not same.
    b. It is seen from the results that the demand and generation access zones are different even when they are located in the same geographical area. For better physical interpretation would it be possible to have demand and generation access charges for common set of zones? Till such time, would it

be appropriate to consider the nodal generation access charges as mirror image of the nodal demand access charges in any zone. If demand access charge is high the generation access charges should be low.

c. It is expected that the nodal demand/generation access charges and the % losses should give a signal for siting of generators and planned loads (like industrial area, SEZs etc.) in various geographical areas of the country. It is understood that the computations have been done with respect to the 400 kV nodes in the truncated network. As a result the computed nodal charges for a particular zone appear to be representative in cases where the 400 kV ISTS is interconnected strongly with the local State system (say Chattisgarh, Uttar Pradesh, Jharkhand). For areas where the ISTS for evacuation of ISGS is not strongly interconnected with the local State system (Himachal Pradesh, Uttarakhand) the results appear to be skewed. Likewise the results do not appear to be representative for areas where ISGS is not switched at 400 kV.

d. The generation Zonal charges for Kerala is taken as average value of that of Tamil Nadu-North and Tamil Nadu-South. This may be reviewed as siting of a new generator in Kerala (at a dead end of the grid) would drastically reduce the zonal charges. This is also evident from the very high demand zonal charges of ps.18.02 /kW/hr charges which are comparable with that of Punjab. This is further strengthened by the fact that the generation losses for Kerala are low (0.72%), where as demand losses are high (6.81%).

e. The zonal access charges for UT-Pondicherry, UT-Goa, UT-Chandigarh may be specified.

f. In Table A.5 of the appendix the there are three sets of data for generation losses in HP area. The % losses for HP-Nathpa Jhakri area is 1.37 %, HP-Chamera area is 0.91% and HP-Dehar area is 0.37 %. This wide variation is not clear.

g. NER has been classified as one generation zone and demand zone. This may be reviewed and suitably addressed.

h. The results for grid generation nodal charges indicate that power schedules for individual units have been considered and the total cost (Rs. Lakh) has been apportioned to the units in proportion to the respective schedules. The generation schedules issued by RLDCs are for a station as a whole. Therefore the need for unit-wise schedule and cost apportionment is yet to be understood.

i. There would be several control areas that would have net injection (instead of withdrawal) during some months. For example Himachal Pradesh has a negative schedule on several days when hydro is at peak. This implies that during these scenarios H.P. nodes would be shown as fictitious generators.

The algorithm would give generation access charges. Does this mean that the demand access charges would be zero for H.P. buses?

j. Transmission constraint and network constraints are to be taken into account by NLDC for notifying approved generation / demand (It leads to TTC computation for each control area). How to take care of long term contracted quantum in case withdrawal capability of a demand customer is much below contracted quantum which is generally the case in case of most NER States especially during low hydro season.

k. A few inconsistencies appear in the case of MP (transmission losses only), NER, Orissa and Uttarakhand (both transmission charges as well as losses), and TN-S (transmission charges only). This needs to be checked further to eliminate any modelling errors.

l. In some cases distance sensitivity is not seen. For example;

   (i) Chhattisgarh to Madhya Pradesh **Vs** Chhattisgarh to Gujarat : the later is cheaper

   (ii) Orissa to Punjab **Vs** HP to Punjab: the former is cheaper

m. In Table-A.3 the demand zonal charges of Goa have been given but that of UT-Daman & Diu and Dadra Nagar Haveli are missing.

XXXXXXXXXXXXX